ORAL ARGUMENT NOT YET SCHEDULED

No. 23-1173

IN THE

United States Court of Appeals for the District of Columbia Circuit

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA,

Petitioner,

v.

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION AND UNITED STATES DEPARTMENT OF TRANSPORTATION,

Respondents,

On Petition for Review of a Final Rule from the United States Department of Transportation and Pipeline and Hazardous Materials Safety Administration

INITIAL BRIEF FOR PETITIONER INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

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CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

A. PARTIES

The following are parties in this Court:

a. Petitioner: Interstate Natural Gas Association of America (INGAA).

b. Respondents: United States Department of Transportation and Pipeline and Hazardous Materials Safety Administration (PHMSA).

There are no *amici* or intervenors.

B. CORPORATE DISCLOSURE STATEMENT

INGAA is an incorporated, not-for-profit trade association representing virtually all interstate natural gas pipeline companies operating in the United States. INGAA has no parent companies, subsidiaries, or affiliates that have issued publicly traded stock. Most INGAA member companies are corporations with publicly traded stock.

INGAA has 26 member companies. They are: BHE GT&S; Boardwalk Pipelines; Cheniere Energy, Inc.; DT Midstream; DTE Energy; Eastern Shore Natural Gas; Enbridge Energy; Equitrans Midstream; Iroquois Pipeline Operating Company; Kinder Morgan, Inc.; Millennium Pipeline Company, LLC; Mountain West Pipeline; National Grid; National Fuel Gas Supply Corporation; NextEra Energy; ONEOK, Inc; Pacific Gas and Electric; Sempra LNG; Southern Company Gas; Southern Star Central Gas Pipeline, Inc.; Spire, Inc.; TC Energy; Tellurian,

Inc.; The Williams Companies; UGI Energy Services, LLC; and WBI Energy Transmission, Inc.

C. RULINGS UNDER REVIEW

INGAA seeks review of five standards contained within PHMSA's Final Rule entitled *Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments*, 87 Fed. Reg. 52,224 (Aug. 24, 2022). PHMSA issued technical corrections and responded to petitions for reconsideration in April 2023. *See Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments; Technical Corrections; Response to Petitions for Reconsideration*, 88 Fed. Reg. 24,708 (Apr. 24, 2023).

D. RELATED CASES

Counsel is not aware of any related cases within the meaning of Circuit Rule 28(a)(1)(C).

/s/ Catherine E. Stetson
Catherine E. Stetson

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GLOSSARY

1.25-times-MAOP standard	Immediate repair requirements codified at 49 C.F.R. § 192.714(d)(1)(v)(C) and § 192.933(d)(1)(v)(C)
ANSI	American National Standards Institute
APA	Administrative Procedure Act
ASME	American Society of Mechanical Engineers
Corrosive-constituent standard	Requirement for pipelines to monitor "corrosive constituents," codified at 49 C.F.R. § 192.478(a)
ERW	Electric Resistance Welded
GPAC	Gas Pipeline Advisory Committee
HF-ERW	High-Frequency Electric Resistance Welded
HF-ERW standard	Requirement to immediately repair metal loss on the seams of HF-ERW pipe, codified at 49 C.F.R. § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv)
INGAA	Interstate Natural Gas Association of America
LF-ERW	Low-Frequency Electric Resistance Welded
MAOP	Maximum Allowable Operating Pressure
NPRM	Notice of Proposed Rulemaking
PHMSA	Pipeline and Hazardous Materials Safety Administration
PRIA	Preliminary Regulatory Impact Assessment
RIA	Regulatory Impact Assessment

Safety-factor-5 standard	Requirement for pipelines to use a "safety factor of 5 or greater for the assessment internal," codified at 49 C.F.R. § 192.712(c)(9)
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessments
SCCDA-pipeline-segment standard	Requirement for pipelines to conduct a minimum of three direct examinations within "the covered pipeline segment," codified at 49 C.F.R. § 192.929(b)(3)

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INITIAL BRIEF FOR PETITIONER INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

JURISDICTIONAL STATEMENT

The Pipeline and Hazardous Materials Safety Administration (PHMSA) denied the Interstate Natural Gas Association of America's (INGAA's) petition for reconsideration on April 24, 2023. JA__ (Final Rule Technical Corrections, 88 Fed. Reg. 24,708 (Apr. 24, 2023)). INGAA timely petitioned for review on July 10, 2023. *See* 49 U.S.C. § 60119(a)(1) (requiring petitions to be filed within 89 days); *I.C.C. v. Brotherhood of Locomotive Engineers*, 482 U.S. 270, 284-285 (1987) (timely petition for administrative reconsideration tolls time to petition for review). This Court has jurisdiction under 49 U.S.C. § 60119(a).

INTRODUCTION

In *GPA Midstream Association v. United States Department of Transportation*, 67 F.4th 1188 (D.C. Cir. 2023), this Court held that PHMSA's new safety standards for gas gathering were procedurally flawed and substantively unreasonable. As this Court explained, PHMSA had failed to subject its proposed safety standards to a preliminary cost-benefit analysis, as required by statute—rendering it procedurally deficient. *Id.* at 1196-98. And PHMSA's final gas gathering rule had failed to adequately explain why its benefits justified its costs—rendering it unreasonable. *Id.* at 1999-1202.

Four months after PHMSA issued the final rule this Court later vacated in *GPA Midstream*, it issued a different sweeping final rule making hundreds of changes to the Federal Pipeline Safety Regulations, codified at 49 C.F.R. Part 192 and governing safety standards for gas transmission pipelines. INGAA and its members supported this rule in great part. But, INGAA explained to PHMSA, a handful of new safety standards—of the approximately 275 changes that the Final Rule codified—provided little to no safety benefit and imposed massive costs on pipeline operators.

PHMSA finalized these standards anyway, along with additional unsupported and brand-new standards. *See* JA__-__ (Final Rule, 87 Fed. Reg. 52,224-79 (Aug. 24, 2022)). INGAA challenges five of those standards here on

both procedural and substantive grounds. Procedurally, four of PHMSA's five contested standards failed to offer a preliminary cost-benefit analysis, violating 49 U.S.C. § 60102(b)(3)(B)'s command and committing the same error that this Court identified in *GPA Midstream*, 67 F.4th at 1196-98. The fifth standard was also procedurally defective; PHMSA failed to consider the recommendations of the Technical Pipeline Safety Standards Committee (aka the Gas Pipeline Advisory Committee (GPAC)), as the governing statute requires. PHMSA also failed to properly notice two of its five contested standards, as required under the Administrative Procedure Act (APA).

PHMSA's five contested standards fare no better on substance. *All five* of these final standards failed to reasonably explain why their benefits "justify" their costs, 49 U.S.C. § 60102(b)(5)—just as PHMSA failed to do in *GPA Midstream*. 67 F.4th at 1199-1201. PHMSA asserted it had no legal obligation to conduct a targeted cost-benefit analysis for its specific safety standards. *GPA Midstream* soundly rejected PHMSA's loose interpretation of its statutory obligation. Section 60102(b)(5) requires that PHMSA make a "reasoned determination that the benefits" of an intended standard "justify its costs." That requirement is demanding, and PHMSA fails to satisfy it—just like in *GPA Midstream*.

This Court should sever and vacate PHMSA's five contested standards contained within the omnibus Final Rule. The hundreds of other safety standards that the Final Rule codifies can and should remain in effect.

ISSUES PRESENTED

1. Whether the HF-ERW standard, the 1.25-times-MAOP standard, the SCCDA-pipeline-segment standard, and the safety-factor-5 standard should be vacated because PHMSA never conducted a preliminary cost-benefit assessment for these standards, as 49 U.S.C. § 60102(b)(3)(B) requires.

2. Whether PHMSA's corrosive-constituent standard should be vacated because PHMSA failed to consider GPAC's "recommendation," as 49 U.S.C. § 60102(b)(2)(G) requires.

3. Whether PHMSA's safety-factor-5 standard should be vacated because the topic it regulates is wholly absent from PHMSA's notice of proposed rulemaking.

4. Whether PHMSA's 1.25-times-MAOP standard should be vacated because PHMSA's notice of proposed rulemaking expressly disavowed any intention of changing the standard it subsequently changed.

5. Whether all five of PHMSA's contested standards should be vacated on merits grounds because they failed to make a "reasoned determination that the

benefits" of the standards "justify" their costs, as 49 U.S.C. § 60102(b)(5) requires, or were otherwise unreasonable under this Court's precedents.

STATEMENT OF THE CASE

I. KEY PLAYERS.

Congress delegates responsibility to "prescribe minimum safety standards for pipeline transportation" to the Secretary of Transportation. *See* 49 U.S.C. § 60102(a)(2). The Secretary delegates that authority to PHMSA. *See* 49 C.F.R. § 1.97.

49 U.S.C. § 60115 establishes and sets out the duties of GPAC,[1] which is composed of 15 members. Those members are appointed by the Secretary of Transportation, *id.* § 60115(b)(1), and represent a mix of governmental agencies, industry representatives, and the public, *id.* § 60115(b)(3). GPAC is responsible for conducting peer reviews and advising PHMSA on the "technical feasibility, reasonableness, cost-effectiveness, and practicability" of its proposed safety standards. *Id.* § 60115(c)(2). PHMSA is required to consider "the comments and recommendations of [GPAC]" when promulgating rules. *Id.* § 60102(b)(2)(G).

[1] *See also* PHMSA, *Gas Pipeline Advisory Committee (GPAC) Charter – October 2022 to October 2024* (Nov. 14, 2022), https://www.phmsa.dot.gov/standards-rulemaking/pipeline/gas-pipeline-advisory-committee-gpac-charter-october-2022-october-2024

Petitioner INGAA is a trade association representing virtually all major interstate natural gas pipeline companies operating in the United States. Pipeline safety is a top priority for INGAA and its members. JA__ (INGAA Comments 7) (AR PHMSA-2011-0023-0407).[2] INGAA regularly works with PHMSA, as well as state regulators and other public advocacy groups, to help develop standards that promote safe pipeline practices while maintaining the reliable delivery of natural gas. JA__-__ (INGAA Comments 7-8). Its members are listed on pages (i) and (ii) of this brief.

II. STANDARDS UNDER REVIEW.

In August 2011, PHMSA initiated an advance notice of proposed rulemaking seeking broad comments on whether "changes [were] needed to the regulations governing the safety of gas transmission pipelines." JA__ (76 Fed. Reg. 53,086, 53,086 (Aug. 25, 2011)). Five years later, PHMSA issued its notice of proposed rulemaking (NPRM) proposing extensive changes to the Federal Pipeline Safety Regulations, codified at 49 C.F.R. Part 192. JA__ (NPRM, 81 Fed. Reg. 20,722 (Apr. 8, 2016)). INGAA provided formal comments on PHMSA's proposal. JA__-__ (INGAA Comments 1-220). GPAC members met several times between 2017 and 2018, submitting a series of recommended changes to

[2] "JA" refers to the Joint Appendix. Citations beginning with "AR" refer to PHMSA's administrative docket.

PHMSA's proposal. *E.g.*, JA__-__ (GPAC Meeting Final Voting Slides 1-52) (AR PHMSA-2011-0023-0656).

PHMSA issued its Final Rule in August 2022, JA__-__ (Final Rule, 87 Fed. Reg. 52,224-79), along with its final Regulatory Impact Analysis (RIA), JA__-__ (RIA 1-49) (AR PHMSA-2011-0023-0637). INGAA "strongly support[ed]" the Final Rule and "publicly championed" its finalization. JA__ (Petition for Reconsideration 1) (AR PHMSA-2011-0023-0641). Out of the Final Rule's hundreds of new requirements, INGAA petitioned PHMSA to reconsider or clarify just a handful. The background relevant to the five standards INGAA challenges in this petition for review is set out below.

A. PHMSA's new requirement to monitor potentially "corrosive constituents" ("corrosive-constituent standard").

First, PHMSA's Final Rule amends 49 C.F.R. § 192.478(a) to require pipelines to monitor "corrosive constituents" in the gas they transport. *See* JA__ (Final Rule, 87 Fed. Reg. at 52,270)

1. Technical background.

For years, 49 C.F.R. § 192.477 has required natural-gas pipelines to monitor "corrosive gas," a catch-all term for any gas containing "[k]nown causes of internal corrosion." *In re: Consumers Energy Co. (F/K/A Mich. Gas Storage Co.)*, 2009 WL 7796885, at *2 (D.O.T. Mar. 5, 2009). Corrosive gas can cause the pipeline's internal walls to corrode, or "thin[]." *Pipeline Safety: Internal Corrosion in Gas*

Transmission Pipelines, 65 Fed. Reg. 53,803, 53,803 (Sept. 5, 2000). Corrosive gas commonly contains "condensates," that is, condensed or liquified water that combines with other substances, such as hydrogen sulfide or carbon dioxide, and then "settle[s] out of the gas stream." *Id.* As these condensates, or other "sediment deposits," travel through or settle in a pipeline, they can corrode its interior walls. *Id.*

Since at least September 2000, pipeline operators have monitored and mitigated corrosive gas in a number of ways. They analyze and measure water content, *id.*; they test the existence and severity of internal corrosion by inspecting the condition and thickness of the pipeline walls, *id.*; they pay special attention to pipeline segments near "gas production and storage fields," where corrosive gas is most likely to exist, *id.*; they closely review conditions in pipeline segments with "sharp bends," which can "restrict" velocity and contribute to corrosive condensates settling out of the gas stream; and they measure corrosion rates in areas where they have reason to believe internal corrosion occurs. *Id.* Pipeline operators also assess levels of carbon dioxide and hydrogen sulfide—not by themselves corrosive—through periodic sampling of the gas stream. JA__ (INGAA Comments 116).

2. PHMSA proposes that pipelines be required to monitor corrosive constituents and estimates it will cost $400,000.

PHMSA's 2016 NPRM proposed adding 49 C.F.R. § 192.478 (previously reserved) to require gas transmission pipelines to "develop and implement a monitoring and mitigation program to identify potentially *corrosive constituents* in the gas being transported and mitigate the corrosive effects." JA__ (NPRM, 81 Fed. Reg. at 20,830) (emphasis added). "Corrosive constituents" include any substance—by itself innocuous—that could potentially become corrosive when combined with other substances. Potentially corrosive constituents "include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either *by itself* or in combination." *Id.* (emphasis added). Section 192.478 marks the first time that PHMSA has required pipelines to monitor "corrosive constituents," not just "corrosive gas." On top of that, PHMSA proposed requiring pipelines to monitor gas with corrosive constituents at any of the *hundreds* of points that such gas "enters the pipeline," rather than with less burdensome, but effective, sampling methods. *Id.* (proposed Section 192.478(b)(1)).

PHMSA's Preliminary Regulatory Impact Assessment (PRIA)—issued in conjunction with its NPRM—analyzed the estimated costs and benefits of its proposed corrosive-constituent standard. PHMSA acknowledged that its proposed standard would require specific monitoring equipment, "including but not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen

sulfide sampling." JA__ (PRIA 88) (AR PHMSA-2011-0023-0117). But, PHMSA assumed, "many operators already have" the required equipment. JA__ (PRIA 90). PHMSA thus concluded that "the added cost of monitoring for CO2, sulfur, water, and other chemicals is either nothing or relatively inexpensive." *Id.* PHMSA opined that the average price of each new piece of required monitoring equipment was $10,000, and that such equipment was needed at only 40 locations (in total, for the entire country). JA__ (PRIA 91 (Table 3-75)). PHMSA's total estimated cost for the corrosive-constituent standard was $400,000. *Id.*

For estimated benefits, PHMSA calculated that the corrosive-constituent standard would "avert approximately three [pipeline safety] incidents per year." JA__ (PRIA 126). PHMSA estimated that each incident cost an average of $300,000, JA__ (PRIA 127), resulting in $900,000 per year of savings.

3. INGAA alerts PHMSA that its proposed corrosive-constituent standard will cost pipelines more than $75 million, and GPAC recommends against it.

INGAA's July 2016 comment letter directly challenged PHMSA's assumption that "the added costs of monitoring [corrosive constituents] is either nothing or relatively inexpensive." JA__ (INGAA Comments 117) (citation omitted). INGAA explained that for many pipelines, a new monitoring system would cost "approximately $250,000 at each point." *Id.* INGAA estimated that prices for newly-required monitoring equipment would range from $30,000 to

$350,000, JA__ (INGAA Cost Analysis 35) (AR PHMSA-2011-0023-0383, Attach. #6), far exceeding the $10,000 per unit that PHMSA estimated.

INGAA's cost analysis also showed that *830* new monitoring systems were needed under PHMSA's proposal to monitor corrosive constituents at each receipt point, *id.*, orders of magnitude more than the 40 new systems that PHMSA estimated. JA__ (PRIA 91). With 830 new monitoring systems costing between $30,000 and $350,000, INGAA calculated that PHMSA's proposed corrosive-constituent standard would cost $75,500,000 to implement. JA__ (INGAA Cost Analysis 35) ("PHMSA dramatically underestimates monitoring equipment costs."); *see also* JA__-__ (INGAA Comments 203-204).

GPAC—the entity responsible for advising PHMSA on its proposed safety standards—recommended that Section 192.478(a) be limited to "the transportation of corrosive gas," not corrosive constituents. JA__ (GPAC Meeting Final Voting Slides 9). One GPAC member explained that requiring pipelines to monitor corrosive constituents at every receipt point would add little benefit because corrosive constituents by themselves do not cause internal corrosion unless water is present, and pipelines already control and monitor the amount of water in their systems. JA__-__ (GPAC Meeting Transcript 210-211 (June 6, 2017) (Zamarin Statement)) (AR PHMSA-2011-0023-0660). GPAC members further requested that PHMSA provide data supporting its proposal and clarify the magnitude of the

problem. JA__-__ (GPAC Meeting Transcript 275, 278 (Jan. 11, 2017) (Campbell and Zamarin Statements)) (AR PHMSA-2011-0023-0660).

4. PHMSA finalizes its corrosive-constituent standard.

Despite GPAC's input and INGAA's alarming cost analysis, PHMSA finalized Section 192.478's new requirement to monitor corrosive constituents without meaningful changes. JA__ (Final Rule, 87 Fed. Reg. at 52,270). In response to comments from GPAC and others, PHMSA's preamble to the Final Rule declared that it would "limit [the final standard's] applicability to the transportation of corrosive gas," parroting the language from GPAC's recommendation. JA__ (Final Rule, 87 Fed. Reg. at 52,238). But PHMSA made no such changes; Section 192.478(a)'s final language still required pipelines to monitor and "evaluate the partial pressure of each corrosive constituent." *Compare* JA__ (Final Rule, 87 Fed. Reg. at 52,270), *with* JA__ (NPRM, 81 Fed. Reg. at 20,830) ("Each operator must evaluate the partial pressure of each corrosive constituent."); *see also* JA__ (Final Rule, 87 Fed. Reg. at 52,270) (imposing monitoring requirements for pipelines "with corrosive constituents in the gas").[3]

[3] PHMSA's final standard added the words "where applicable" and "as necessary" to the third sentence of proposed Section 192.478(a): "An operator must evaluate the partial pressure of each corrosive constituent, *where applicable*, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal

PHMSA's Final Rule also did not analyze the costs or benefits of its corrosive-constituent standard. PHMSA abandoned its preliminary cost-benefit estimate ($400,000 in costs; $900,000 in benefits, *see supra* p. 10), and offered two reasons for omitting a final cost-benefit assessment. First, PHMSA again "assumed" that pipelines "already have the infrastructure in place to comply with § 192.478." JA__ (RIA 25). PHMSA did not respond to INGAA's comment that this assumption was wrong. JA__ (INGAA Comments 117). Second, PHMSA asserted that "precisely how much th[e] compliance costs are is hard to determine because of uncertainties regarding operators' compliance strategies with respect to existing regulations." JA__ (RIA 27). PHMSA did not acknowledge its preliminary cost-benefit assessment or INGAA's cost calculations, JA__ (INGAA Cost Analysis 35)—the very calculations that PHMSA asserted were too difficult to compute.

5. PHMSA denies INGAA's request to reconsider its corrosive-constituent standard.

INGAA petitioned PHMSA for reconsideration, explaining that applying monitoring requirements to corrosive constituents, instead of corrosive gas, improperly departed from GPAC's recommendation without explanation. JA__

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corrosion of the pipe and implement mitigation measures *as necessary*." *Compare* JA__ (Final Rule, 87 Fed. Reg. at 52,270), *with* JA__ (NPRM, 81 Fed. Reg. at 20,830). Otherwise, the proposed and final sentences are identical.

(Petition for Reconsideration 11). INGAA also highlighted (again) that PHMSA's assumption that pipelines already had the necessary monitoring equipment in place was incorrect, making the costs far greater than PHMSA assumed. JA__ (Petition for Reconsideration 13).

PHMSA refused to change its standard. It asserted that it "account[ed] for" GPAC's recommendations, even while acknowledging that its standard requires pipelines to monitor corrosive constituents, not just corrosive gas. JA__ (PHMSA Letter 10). PHMSA also re-asserted, again without evidence and in the face of INGAA's contrary statements, that the costs of its new monitoring requirements were minimal because only a fraction of pipelines would have to take on new "monitoring and mitigation measures." *Id.*

B. PHMSA's new high-frequency electric resistance welded pipe standard ("HF-ERW standard").

Second, PHMSA's Final Rule amends 49 C.F.R. § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) to treat metal loss on the seams of low-frequency *or* high-frequency electric resistance welded (ERW) pipe as a condition that must be immediately repaired (known as an "immediate repair condition"). JA__-__, __ (Final Rule, 87 Fed. Reg. at 52,271-72, 52,277).

1. Technical background.

There are several different ways to manufacture the pipe used in natural-gas pipelines. *See* PHMSA, *Fact Sheet: Pipe Manufacturing Process* (Dec. 1, 2011).[4] One option is ERW pipe. ERW pipe is manufactured by passing an electric current between the two edges of the steel "to form a bond without the use of welding filler material." *Id.* There are two types of ERW pipe. Low-frequency ERW (LF-ERW) uses a low frequency A.C. current to heat the seam of the pipe. *Id.* High-frequency ERW (HF-ERW) uses a high frequency A.C. current. *Id.*

LF-ERW was used from the 1920s until approximately 1970. *Id.* As PHMSA has explained, "[o]ver time, the welds of low frequency ERW pipe [were] found to be susceptible to selective seam corrosion, hook cracks, and inadequate bonding of the seams, so low frequency ERW is no longer used to manufacture pipe." *Id.* The "high frequency process is still being used to manufacture pipe." *Id.*

Metal loss can occur on the seams of both HF-ERW and LF-ERW. *See generally* PHMSA, *Fact Sheet: Pipe Defects and Anomalies* (Dec. 1, 2011).[5]

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[4] https://tinyurl.com/55mdnj4n

[5] https://tinyurl.com/32xp2dxt

Metal loss is the thinning of the pipeline wall "due to internal or external corrosion." *Id.*

Prior to this rulemaking, metal loss in LF-ERW seams, but not HF-ERW seams, required an "immediate response" from pipeline operators. JA__ (INGAA Comments 91). PHMSA's regulations expressly incorporate industry manual ASME/ANSI B31.8S-2004 by reference.[6] *See* 49 C.F.R. § 192.7(c)(6). Section 7.2.1. of that manual considers metal loss affecting LF-ERW seams, but not HF-ERW seams, an "immediate repair condition." JA__ (INGAA Comments 91) (citing ASME/ANSI B31.8S-2004, *Managing System Integrity of Gas Pipelines* 20, Section 7.2.1). A pipeline must begin repairing or removing an "immediate repair condition" within 5 days of detecting it.[7]

2. PHMSA proposes to treat metal loss in the seams of HF-ERW pipe as an immediate repair condition.

PHMSA's 2016 NPRM proposed changing 49 C.F.R. § 192.713(d)(1)(iv) and § 192.933(d)(1)(v) to require pipeline operators to immediately repair any metal loss affecting seams of *either* high-frequency *or* low-frequency ERW. JA__

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[6] ASME is the American Society of Mechanical Engineers. *See* https://webstore.ansi.org/sdo/asme (last visited Dec. 2, 2023). It is accredited by the American National Standards Institute (ANSI) to issue pipeline design and inspection standards. *Id.*

[7] PHMSA, *Final Gas IM FAQs*, FAQ-215 pp. 36-37, (Aug. 26, 2021), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-09/Final%20GAS%20IM%20FAQs%208-26-21.pdf

(NPRM, 81 Fed. Reg. at 20,846). To justify this proposal, PHMSA stated that "line pipe manufactured using *low frequency electric resistance welding* is susceptible to seam failure." JA__ (NPRM, 81 Fed. Reg. at 20,728) (emphasis added). PHMSA never discussed or alluded to risks associated with HF-ERW. PHMSA's accompanying PRIA asserted only that its new standard would not "impose an additional cost burden on pipelines" because, it said, the new standard "relax[es]" the requirements existing at the time. JA__ (PRIA 73-74). There was no further analysis.

3. PHMSA ignores INGAA's comments and finalizes its proposed standard.

INGAA and others explained to PHMSA that metal loss in *high-frequency* ERW pipe (unlike low-frequency) should not be treated as an immediate repair condition. By requiring immediate repair of metal loss in HF-ERW seams, PHMSA's proposed standard would divert pipeline resources and "slow the response to conditions that represent a higher risk to the public and the environment." JA__ (INGAA Comments 92); *see also* JA__ (Petition for Reconsideration 18) (this standard requires operators to "prioritize and direct resources to pipe with HF-ERW seams, when those resources may be more effectively directed to pipe that poses much higher risk").

INGAA's comment letter highlighted that "PHMSA has not explained or provided data to support its proposal to treat metal loss associated with high-

frequency electric resistance welded seams as an immediate repair condition." JA__-__ (INGAA Comments 91-92). INGAA also filed a joint letter with the American Gas Association, American Petroleum Institute, and American Public Gas Association—other owner-operators of gas transmission pipelines—stating that they collectively had "identified zero incidents related to [metal loss] affecting the long seam of HF-ERW pipe from 2010 – 2017." JA__ (June 6, 2018 Joint Comment Letter 10) (AR PHMSA-2011-0023-0451). The associations explained that "[i]t is well-established that HF-ERW pipe is not susceptible to threats like some pre-1970s LF-ERW seam types," and on that basis requested that PHMSA "remove" metal loss to HF-ERW pipes as a new immediate repair condition. *Id.* INGAA also informed PHMSA that metal loss in HF-ERW pipe was *not* considered an immediate repair condition under existing regulations and industry standards, JA__-__ (INGAA Comments 91-92), contrary to PHMSA's assertion and the basis for its preliminary cost-benefit justification, JA__ (PRIA 73-74).

PHMSA finalized its HF-ERW standard in substantially the same form. JA__ (Final Rule, 87 Fed. Reg. at 52,272, 52,277 (codifying 49 C.F.R. §§ 192.714(d)(1)(iv), 192.933(d)(1)(iv)). PHMSA's Final Rule asserted that seams in "high-frequency electric resistance welding" are "more likely to fail." JA__, __ n.53 (Final Rule, 87 Fed. Reg. at 52,252 & 52,261 n.53); *see also* JA__ (Final Rule, 87 Fed. Reg. at 52,261) (asserting that seams formed by HF-ERW are

"susceptible to latent manufacturing defects"). PHMSA's final RIA reiterated the same assertion as the PRIA, without acknowledging INGAA's contrary information: The HF-ERW standard would not "impose an additional cost burden" because it expressly codified industry standards that were "already" in place. JA__-__ (RIA 35-36). PHMSA performed no other cost-benefit analysis for its HF-ERW standard.

4. PHMSA denies INGAA's petition for reconsideration.

INGAA petitioned for reconsideration, requesting that PHMSA remove HF-ERW from Sections 192.714(d)(1)(iv) and 192.933(d)(1)(iv)'s reach because the final RIA failed to "account for the costs and benefits of th[at] provision." JA__ (Petition for Reconsideration 18). INGAA also explained that reconsideration was warranted because PHMSA failed to "explain its analysis of the incident data" it relied on to impose the immediate-repair requirement on HF-ERW. *Id.*

PHMSA denied INGAA's request, without responding to INGAA's argument that it failed to perform the necessary cost-benefit analysis. JA__-__ (PHMSA Letter 11-13). PHMSA justified its HF-ERW standard by citing a handful of expert reports—never previously referenced in these proceedings—to assert that HF-ERW pipe "remains subject to similar weld failure mechanisms as LF-ERW pipe." JA__ (PHMSA Letter 13); *see also* JA__-__ & nn. 26-33 (PHMSA Letter 12-13 & nn. 26-33) (discussing these expert reports).

C. PHMSA's new "predicted failure pressure" standard for pipeline cracks ("1.25-times-MAOP standard").

Third, PHMSA's Final Rule adopts 49 C.F.R. § 192.714(d)(1)(v)(C) and amends § 192.933(d)(1)(v)(C) to require pipelines to immediately repair cracks that carry a predicted failure pressure of less than or equal to 125% of the pipeline's maximum allowable operating pressure (MAOP). JA__, __-__ (Final Rule, 87 Fed. Reg. at 52,272, 52,277-78).

1. Technical background.

A pipeline "anomaly" is "an imperfection in the wall of the pipe." PHMSA, *Pipeline Glossary: Anomaly*.[8] Anomalies include dents and corrosion, *id.*, as well as cracks. A "crack" is an unwanted opening or separation in a pipeline wall. PHMSA, *Pipeline Glossary: Cracks*.[9]

Pipelines with anomalies, including cracks, can burst if the gas pressure in that pipeline becomes too high. The predicted failure pressure is the gas pressure at which a pipeline's anomaly would cause the pipeline to burst.

Maximum allowable operating pressure "means the maximum pressure at which a pipeline or segment of a pipeline may be operated." 49 C.F.R. § 192.3. The

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[8] https://primis.phmsa.dot.gov/Comm/glossary/index.htm#Anomaly

[9] https://primis.phmsa.dot.gov/Comm/glossary/index.htm#Cracks

MAOP is calculated with reference to the pipeline's material, design, and location. *See* 49 C.F.R. §§ 192.619, 192.111.

2. PHMSA's NPRM states it will not raise its 1.1-times-MAOP threshold for immediate repairs.

Under the NPRM's proposed regulations, pipelines would be required to immediately repair any "anomaly" that carried a predicted failure pressure of less than or equal to 1.1 times the pipeline's MAOP. *See* JA__ (NPRM, 81 Fed. Reg. at 20,839, 20,845) (proposed Sections 192.713(d)(1)(i) and 192.933(d)(1)(i)). This requirement would apply to all anomalies, including cracks.

PHMSA noted that the "majority" of stakeholders "supported no changes to the immediate repair criterion of predicted failure pressure of less than or equal to 1.1 times MAOP." JA__ (NPRM, 81 Fed. Reg. at 20,756). It stated, expressly, that it was "not proposing to change this criterion." *Id.*

3. PHMSA's Final Rule codifies a new 1.25-times-MAOP requirement for cracks.

At the March 2018 GPAC meeting—two years after its notice of proposed rulemaking—PHMSA proposed singling out cracks for the first time. *See* JA__ (PHMSA Slide Presentation to GPAC 160 (Mar. 26-28, 2018)) (AR PHMSA-2011-0023-0657). PHMSA suggested making it an immediate-repair condition whenever a crack or crack-like anomaly carried a predicted failure pressure less than or equal to *1.25 times MAOP*. *See id.* Pipeline operators would have to

immediately repair any crack that would cause a failure *if* that pipeline exceeded its maximum pressure by 25%. GPAC voted to approve PHMSA's recommendation, but instructed PHMSA to "consider" a 1.1-times MAOP threshold—not 1.25—for pipelines that "verif[y]" their tools measuring predicted failure pressure are reasonably accurate. JA__ (GPAC Meeting Final Voting Slides 49 (Mar. 28, 2018)) (advocating for 1.1-times-MAOP "after tool tolerance has been field verified and applied").

PHMSA's Final Rule created 49 C.F.R. § 192.714(d)(1)(v)(C) and § 192.933(d)(1)(v)(C) to impose its new 1.25-times-MAOP requirement for cracks. *See* JA__, __-__ (Final Rule, 87 Fed. Reg. at 52,272, 52,277-78). PHMSA stated tersely that it selected 1.25-times-MAOP because its initially-proposed 1.1 threshold was "inadequate." JA__ (Final Rule, 87 Fed. Reg. at 52,248). Its final RIA did not evaluate the costs or benefits of its new 1.25-times-MAOP standard. *See generally* JA__-__ (RIA 1-49); *see also* JA__ n.11 (PHMSA Letter 4 n.11) (acknowledging that PHMSA has never "explicitly discuss[ed]" the "cost-effectiveness" of its 1.25-times-MAOP standard).

4. PHMSA denies INGAA's petition for reconsideration.

INGAA petitioned PHMSA for reconsideration, explaining that the 1.25-times-MAOP standard failed to "consider the factors required under the Pipeline Safety Act," including cost and feasibility. JA__ (Petition for Reconsideration 10).

Moreover, INGAA explained, PHMSA failed to "articulate a satisfactory explanation" for why its new 125%-threshold was needed. JA__ (Petition for Reconsideration 9) (citation omitted).

PHMSA denied INGAA's request. PHMSA claimed it was not subject to any "statut[ory] or regulat[ory]" requirement to explicitly discuss the "cost-effectiveness" of its 1.25-times-MAOP requirement. JA__ n.11 (PHMSA Letter 4 n.11). PHMSA also asserted that a targeted cost-benefit analysis for its new 1.25-times-MAOP standard was not "practicable given PHMSA's comprehensive and highly technical regulatory regime." *Id.* PHMSA stated that it settled on its 1.25-times-MAOP metric because it needed a "conservative MAOP-based threshold for immediate repair." JA__ (PHMSA Letter 3). Without elaborating, PHMSA asserted that its final 1.25-times-MAOP threshold was "carefully selected" and "calibrated." *Id.*

D. PHMSA's new standard for Stress Corrosion Cracking Direct Assessments (SCCDA) ("SCCDA-pipeline-segment standard").

Fourth, PHMSA's Final Rule amends 49 C.F.R. § 192.929(b)(3) to require every Stress Corrosion Cracking Direct Assessment, or "SCCDA," to conduct "a minimum of three direct examinations for SCC [stress corrosion cracking] within the covered pipeline segment." JA__ (Final Rule, 87 Fed. Reg. at 52,276).

1. Technical background

An SCCDA is a process to assess a pipeline's "stress corrosion cracking" (SCC)[10] by performing an excavation of the area surrounding the pipeline. 49 C.F.R. § 192.929(a). After excavating, the SCCDA "gather[s] and analyz[es] excavation data," such as the surrounding soil quality, the presence of in-ground contaminants, and the condition of the pipe itself, to determine if a pipeline is experiencing SCC. *Id.* PHMSA refers to each excavation and analysis of excavation data as a "direct examination." JA__ (Final Rule, 87 Fed. Reg. at 52,244).

Although PHMSA has never defined the term, "SCC segment" most naturally refers to the pipeline segment being examined under a given SCC Direct Assessment. *See* JA__-__ (Petition for Reconsideration 26-27).

2. PHMSA's proposed SCCDA standard.

PHMSA's Notice of Proposed Rulemaking sought to update the standards used to conduct SCCDAs. JA__-__ (NPRM, 81 Fed. Reg. at 20,773-74). PHMSA proposed amending 49 C.F.R. § 192.929(b)(3) to require each SCCDA to

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[10] Stress corrosion cracking "produces a marked loss of pipeline strength with little metal loss." *See* PHMSA, *Fact Sheet: Stress Corrosion Cracking* (July 23, 2014), https://primis.phmsa.dot.gov/comm/FactSheets/FSStressCorrosion.htm. It occurs when a pipeline cracks, and weakens, from being "under higher pressures (stress)." *Id.*

"conduct[] a minimum of three direct examinations within the *SCC segment* at locations determined to be the most likely for SCC to occur." JA__ (NPRM, 81 Fed. Reg. at 20,845) (emphasis added). Both GPAC and INGAA supported that proposed amendment. *See* JA__ (GPAC Meeting Final Voting Slides 21 (Dec. 15, 2017); JA__, __-__ (INGAA Comments 155, 166-167) (suggesting changes for proposed Section 192.921, but leaving Section 192.929 untouched).

3. PHMSA's final SCCDA-pipeline-segment standard.

Without notice or explanation, however, PHMSA's Final Rule changed that language to instead require each SCCDA to conduct "a minimum of three direct examinations for SCC within the *covered pipeline segment*." JA__ (Final Rule, 87 Fed. Reg. at 52,276) (emphasis added).[11] That language change matters. Many SCC segments have three or four "covered pipeline segments" within them. *See* JA__-__ (Petition for Reconsideration 26-27). PHMSA's Final Rule even appeared to acknowledge that. *See* JA__ (Final Rule, 87 Fed. Reg. at 52,276) (Section 192.929(b)(1): noting a single SCCDA must "collect and evaluate data for *all* covered pipeline segments" being assessed (emphasis added)). Thus, PHMSA's change could triple or quadruple the number of direct examinations an

[11] Section 192.903 defines "covered segment" as "a segment of gas transmission pipeline located in a high consequence area." JA__ (Final Rule, 87 Fed. Reg. at 52,243). The boundaries of a covered segment are "determined by population density and other consequence factors." *Id.*

operator was required to perform under PHMSA's proposed standard. *See* JA__-__ (Petition for Reconsideration 26-27). PHMSA's Final Rule and final RIA did not evaluate the costs or benefits of requiring this multiplicity of direct examinations per "covered pipeline segment."

4. PHMSA denies INGAA's request for reconsideration.

INGAA petitioned PHMSA for reconsideration, requesting that PHMSA change 49 C.F.R. § 192.929(b)(3) back to the language originally proposed, so that pipelines must perform three direct examinations per "SCC segment," not per "covered pipeline segment." JA__-__ (Petition for Reconsideration 26-27). INGAA explained that PHMSA's late-breaking change could dramatically increase the number of required excavations and that PHMSA had performed no analysis—quantitative or qualitative—to justify that new requirement. *Id.* PHMSA denied INGAA's request, giving no explanation for why the benefits of its new requirement for three excavations within each "covered pipeline segment" outweighed the costs. JA__ (PHMSA Letter 15).

E. PHMSA's new standard requiring a safety factor of 5 for fatigue life assessments ("safety-factor-5 standard").

Fifth, PHMSA's Final Rule amends 49 C.F.R. § 192.712(c)(9) to require every fatigue life assessment for pipeline dents to use a "safety factor of 5 or greater for the assessment interval." JA__ (Final Rule, 87 Fed. Reg. at 52,271).

1. Technical background.

A "dent" is a deformation in a pipeline caused by external forces. JA__ (INGAA Comments, Attach. #9, p. 22). Dents result in pipeline "fatigue," a technical term for "structural degradation" caused by "stress or strain." JA__ (INGAA Comments, Attach. #9, p. 2). If left unchecked, fatigue can cause a pipeline to "fracture," or burst. JA__ (INGAA Comments, Attach. #9, p. 8).

A dent's "fatigue life," which is calculated by performing a fatigue life assessment, refers to the amount of time it would take for the dent to cause the pipeline to fracture. *See* JA__ (Final Rule, 87 Fed. Reg. at 52,271). Fatigue life assessments are assigned a "safety factor" which then determines the dent's "reassessment interval." *Id.* For example, if a fatigue life assessment determines that a dent's fatigue life is 30 years, then a safety factor of 2 would require reassessment (i.e., another fatigue life assessment) within 15 years. A safety factor of 3 would require reassessment within 10 years, and so on.

2. PHMSA's Final Rule requires fatigue life assessments to use a safety factor of 5.

PHMSA did not include any proposal to change the safety factor for fatigue life assessments in its April 2016 NPRM or its accompanying PRIA. At the March 2018 GPAC meeting, PHMSA proposed a number of *new* requirements governing the methods used to assess predicted failure pressure and pipeline strain. JA__-__ (PHMSA Slide Presentation to GPAC 146-153). One such proposal was to require

fatigue life assessments for dents to use a safety factor of 2. JA__ (PHMSA Slide Presentation to GPAC 149). GPAC unanimously approved PHMSA's new proposals. JA__ (GPAC Meeting Final Voting Slides 47).

Without warning, PHMSA's final Section 192.712(c)(9) required fatigue life assessments for dents to use a "safety factor of *5 or greater* for the assessment interval." JA__ (Final Rule, 87 Fed. Reg. at 52,271) (emphasis added). That super-sized the safety factor of 2 that GPAC approved in March 2018. PHMSA's Final Rule offered no explanation for why a safety factor of 5 was warranted and provided no assessment of the costs or benefits for its new requirement.

3. PHMSA denied INGAA's petition for reconsideration.

PHMSA's safety-factor-5 standard will require operators to devote key "resources to non-critical safety tasks." JA__ (Petition for Reconsideration 15). With this standard, operators will perform more than twice as many fatigue analysis reassessments "without any discernable safety benefit." *Id.*

INGAA petitioned PHMSA for reconsideration, arguing that PHMSA's new safety-factor-5 standard "was not proposed in the NPRM or discussed by GPAC." *Id.* PHMSA also explained that requiring five fatigue life reassessments before a dent is expected to cause a failure "significantly" increases costs while providing no additional safety benefit at all. *Id.*

PHMSA denied INGAA's request. JA__ (PHMSA Letter 8). It did not defend its failure to include the safety-factor-5 standard in its NPRM. It declined to revise that safety factor because, it stated, a 2020 report published by the American Petroleum Institute—never before referenced in these proceedings or discussed at any GPAC meeting—"recommend[ed] use of [safety] factors between 2 and 5." JA__-__ (PHMSA Letter 8-9). PHMSA also offered that if an operator "has a safety-based rationale" for using a lower safety factor, the operator "may seek PHMSA permission to use that lower reassessment safety factor." JA__ (PHMSA Letter 9).

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PHMSA's Final Rule makes changes to hundreds of standards in the Federal Pipeline Safety Regulations. INGAA challenges just five: (1) the corrosive-constituent standard; (2) the HF-ERW standard; (3) the 1.25-times-MAOP standard; (4) the SCCDA-pipeline-segment standard; and (5) the safety-factor-5 standard.

STATUTES AND REGULATIONS

Pertinent statutes and regulations are reprinted in the addendum.

STANDARD OF REVIEW

This Court reviews de novo whether an agency has complied with the APA's procedural requirements for notice and comment. *Sorenson Commc'ns Inc. v. FCC*, 755 F.3d 702, 706 n.3 (D.C. Cir. 2014). De novo review also applies to

whether PHMSA has complied with the procedural requirements set forth in its authorizing statute. *See GPA Midstream*, 67 F.4th at 1196-98 (offering no deference to PHMSA's arguments that it properly "[o]bserve[d]" Section 60102(b)'s "[r]ulemaking [p]rocedures").

On the merits, this Court defers to PHMSA's "factual findings and expert judgments," *Sorenson Commc'ns*, 755 F.3d at 706 n.3, but "only if it has adequately explained the basis" for them, *Bluewater Network v. EPA*, 370 F.3d 1, 22 (D.C. 2004). This Court does not "defer" to PHMSA's assertions that it has "satisfied its statutory duty" to conduct a final cost-benefit analysis under Section 60102(b)(5) unless that assertion is adequately explained and "informed." *GPA Midstream*, 67 F.4th at 1199.

SUMMARY OF ARGUMENT

Five standards in PHMSA's Final Rule should be set aside: (1) the corrosive-constituent standard; (2) the HF-ERW standard; (3) the 1.25-times-MAOP standard; (4) the SCCDA-pipeline-segment standard; and (5) the safety-factor-5 standard. Each is procedurally defective and substantively unreasonable.

I. All of PHMSA's contested standards violate Section 60102(b)'s procedural requirements. *See infra* pp. 35-43. Four of them—the HF-ERW standard, the 1.25-times-MAOP standard, the SCCDA-pipeline-segment standard, and the safety-factor-5 standard—failed to conduct the *preliminary* cost-benefit

assessment that Section 60102(b)(3)(B) requires. *See GPA Midstream*, 67 F.4th at 1197-99.

The corrosion-constituent standard violated Section 60102(b)(2)(G)'s requirement that PHMSA "consider" GPAC's recommendations. GPAC recommended that PHMSA "[l]imit the applicability of paragraph (a) [in § 192.478] to the transportation of corrosive gas." JA__ (GPAC Meeting Final Voting Slides 9). The prefatory statements in PHMSA's Final Rule responded that PHMSA would implement GPAC's recommended limitation. JA__ (Final Rule, 87 Fed. Reg. at 52,238). But the Final Rule never did. By failing to implement GPAC's recommendation, or explain why it refused to, PHMSA violated Section 60102(b)(2)(G).

II. PHMSA's 2016 NPRM failed to include its safety-factor-5 and 1.25-times-MAOP standards. *See infra* pp. 43-46. The safety-factor-5 standard, and fatigue life assessments more generally, are not in PHMSA's 2016 NPRM. *See* JA__-__ (NPRM, 81 Fed. Reg. at 20,722-856). That violates the APA's bedrock requirement for PHMSA to provide notice of its proposed rule.

Meanwhile, PHMSA expressly stated that it would not "change" its standard that pipelines must immediately repair anomalies that carry a "predicted failure pressure of less than or equal to 1.1 times MAOP." JA__ (NPRM, 81 Fed. Reg. at 20,756). But then it did, issuing its new and final 1.25-times-MAOP standard.

This Court does not permit such "complete turnaround[s] from the NPRM." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1082 (D.C. Cir. 2009).

III. On the merits, all of PHMSA's five contested standards were unreasonable. In addition to the *procedural* requirement to provide a preliminary cost-benefit analysis at the NPRM stage, 49 U.S.C. § 60102(b)(3)(B), PHMSA has a *substantive* duty to issue final rules based on its "reasoned determination" that the standard's benefits "justify its costs," 49 U.S.C. § 60102(b)(5); *see GPA Midstream*, 67 F.4th at 1197-1201. PHMSA's Final Rule substantively failed to explain how the benefits justified the costs for *each* challenged standard.

For the corrosion-constituent standard, PHMSA asserted that omitting a final cost-benefit assessment was permissible because only a fraction of pipelines would be impacted by the new standard and, alternatively, because costs were too difficult to quantify. JA__, __ (RIA 25, 27). PHMSA made similar assertions in *GPA Midstream*, and this Court rejected them. 67 F.4th at 1200; *see infra* pp. 47-50.

For the HF-ERW standard, PHMSA asserted that its new standard imposed no new costs because pipelines were already complying with it. JA__-__ (RIA 35-36). That assertion was contradicted in the record, JA__-__ (INGAA Comments 91-92), and PHMSA's continued reliance on it was unreasonable. *See infra* pp. 50-54.

For the 1.25-times-MAOP standard, PHMSA's pre-*GPA Midstream* assertion that it had no legal obligation to perform targeted cost-benefit analyses withers away in the post-*GPA Midstream* legal landscape. Moreover, PHMSA unreasonably failed to explain why its 1.25-times-MAOP strikes the right balance between additional immediate-repair costs and safety benefits. *See Bluewater Network*, 370 F.3d at 21; *infra* pp. 54-58.

PHMSA also failed to consider the costs and benefits of its new SCCDA-pipeline-segment and safety-factor-5 standards. *See infra* pp. 58-60. PHMSA's additional justification that operators could seek waivers to go beneath its default safety factor of 5 is also meritless. *See infra* p. 61. This Court rejected that argument in *GPA Midstream*, 67 F.4th at 1199, and should do so again now.

STANDING

INGAA's standing is self-evident. INGAA's 26 members are listed on pages (i) and (ii) of this brief, and they are "directly regulated by the Final Rule." *Advocates for Highway & Auto Safety v. Federal Motor Carrier Safety Admin.*, 41 F.4th 586, 594 (D.C. Cir. 2022) (holding Article III associational standing exists under such circumstances).

The record demonstrates that each challenged standard gives rise to "concrete, particularized pocketbook injury" for INGAA's members. *Maine Lobstermen's Ass'n v. National Marine Fisheries Serv.*, 70 F.4th 582, 592 (D.C.

Cir. 2023). The corrosive-constituent standard will force INGAA's members to purchase new monitoring equipment that costs "approximately $275,000." JA__ (INGAA Comments 204). The HF-ERW standard will require INGAA's members to "deploy pipeline integrity resources at the expense of higher-risk conditions elsewhere." JA__ (INGAA Comments 91). The 1.25-times-MAOP standard will force operators to immediately repair cracks that would otherwise be safely repaired "in the one to two year timeframe." JA__ (GPAC Meeting Transcript 232 (Mar. 2, 2018) (Carey Statement)) (AR PHMSA-2011-0023-0660). The SCCDA-pipeline-segment standard and the safety-factor-5 standard will require more excavations and more reassessments, respectively—directly increasing operators' costs. JA__, __-__ (Petition for Reconsideration 15, 26-27).

INGAA has associational standing because this suit is germane to its purposes and there is no reason individual pipeline operators must participate in it. *Maine Lobsterman's Ass'n*, 70 F.4th at 593; *National Lime Ass'n v. EPA*, 233 F.3d 625, 636 (D.C. Cir. 2000) (germaneness requirement is "undemanding"); *see also, e.g.*, *Lake Carriers' Ass'n v. EPA*, 652 F.3d 1, 5 & n.2 (D.C. Cir. 2011) (holding individual members need not participate where trade association challenged rule for "fail[ure] to consider" compliance costs and failure to provide adequate notice).

ARGUMENT

I. ALL FIVE CONTESTED STANDARDS IN PHMSA'S FINAL RULE VIOLATED 49 U.S.C. 60102'S PROCEDURAL REQUIREMENTS.

Section 60102's rulemaking procedures "are more specific and still more demanding" than those under the Administrative Procedures Act. *GPA Midstream*, 67 F.4th at 1197; *see also id.* at 1192 (explaining PHMSA must follow hybrid "detailed rulemaking procedures" under both Section 60102 and the APA). PHMSA must "identify the costs and benefits associated with [its] proposed standard" in a preliminary risk assessment and then "submit th[e] risk assessment" to GPAC for review and "to the public for comment." *Id.* (quoting 49 U.S.C. § 60102(b)(3)(B), (4)). Moreover, PHMSA's rule "shall consider" GPAC's "comments and recommendations." 49 U.S.C. § 60102(b)(2)(G). All five of PHMSA's contested standards fail to comply with at least one of these requirements.

A. For four contested standards, PHMSA failed to provide the required preliminary cost-benefit analysis.

PHMSA's HF-ERW standard, the 1.25-times-MAOP standard, the SCCDA-pipeline-segment standard, and the safety-factor-5 standard *each* failed to provide a preliminary cost-benefit assessment. That is reason enough to set these standards aside.

GPA Midstream—decided less than a year ago—squarely applies here. In *GPA Midstream*, PHMSA issued a final rule requiring both transmission pipelines

(which transport gas and oil long distances) and gathering pipelines (which collect raw gas or crude oil from wells) to install remote-controlled or automatic shut-off valves. 67 F.4th at 1191. PHMSA's preliminary risk assessment, issued with its notice of proposed rulemaking, "contained no data, analysis, or conjecture about the costs and benefits of applying the proposed safety standard to gathering facilities." *Id.* at 1196-98. This Court held that this omission violated Section 60102(b)(3)(B) and Section 60102(b)(4)'s requirements and vacated PHMSA's rule as it applied to gathering pipelines. *See id.* at 1196-99. In the Court's words, by failing "to identify the costs and benefits" of its proposed rule in a preliminary risk assessment, "PHMSA flouted the pipeline safety laws and a cardinal rule of administrative law." *Id.* at 1198.

PHMSA repeated the same error here. *First*, PHMSA's NPRM proposed revising Section 192.933(d)(1)(v) to include its new HF-ERW standard. *See* JA__ (NPRM, 81 Fed. Reg. at 20,846). Pages 73-74 of PHMSA's accompanying PRIA purported to analyze that standard's costs and benefits. *See* JA__-__ (PRIA 73-74). But all the PRIA stated was that "by limiting the immediate condition to significant selective seam corrosion," PHMSA's new standard was not "impos[ing] additional cost burden[s] on pipeline operators." *Id.* This "significant selective seam weld corrosion" standard, however, refers to a different provision, Section 192.933(d)(1)(vii). *See* JA__ (NPRM, 81 Fed. Reg. at 20,846) (making "[a]ny

indication of significant seam weld corrosion" an immediate repair condition). It is different from proposed subsection (v)'s requirement to treat *any* metal loss in seams of HF-ERW pipe as an immediate repair condition—the standard INGAA contests here. *Id.*

Selective seam corrosion and metal loss in the seams of HF-ERW are separate issues. As PHMSA recognizes, selective seam corrosion occurs "along the bond line of low-frequency electric resistance welding (LR-ERW) and electric flash welding (EFW) piping," *not* HF-ERW pipe. *See* PHMSA, *Fact Sheet: Selective Seam Corrosion (SSC)* (Dec. 1, 2011);[12] *see also* JA__ (INGAA Comments 91) ("Corrosion-related metal loss interacting with high-frequency electric resistance weld seams is not subject to selective seam weld corrosion."). Because PHMSA's PRIA never analyzed the costs and benefits of its separate (and costly) HF-ERW standard, it failed "to do an adequate risk assessment in time for peer review and public comment." *GPA Midstream*, 67 F.4th at 1197-98.

Second, no cost-benefit analysis was done for PHMSA's 1.25-times-MAOP standard. The 2016 PRIA analyzed the costs and benefits for some of PHMSA's newly proposed "[r]epair [c]riteria," such as requiring that metal loss exceeding 80% of wall thickness be immediately repaired. *See* JA__-__ (PRIA 72-73). But

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[12] https://tinyurl.com/mwh5ux7u

because PHMSA's 1.25-times-MAOP standard was not under consideration at this time (PHMSA disavowed any intention to consider it, *see infra* p. 44), PHMSA's PRIA does not mention it. PHMSA's NPRM and accompanying PRIA did not even consider separating cracks out from other anomalies—as the Final Rule later did. *Compare* JA__ (NPRM, 81 Fed. Reg. at 20,839) (proposed Section 192.713(d)(1)(i) applying to any "anomaly" with a predicted failure pressure less than or equal to 1.1-times MAOP), *with* JA__ (Final Rule, 87 Fed. Reg. at 52,272) (final Section 192.714(d)(1)(v)(C)) ("The crack or crack-like anomaly has a predicted failure pressure . . . that is less than 1.25 times the MAOP."). So of course PHMSA did not provide a *preliminary* cost-benefit assessment of its final crack-specific 1.25-times-MAOP standard. That improperly denied the public "a meaningful chance of participating in the rulemaking process." *GPA Midstream*, 67 F.4th at 1197.

Third, the estimated costs and benefits of PHMSA's standard requiring SCCDAs to conduct three examinations *per covered pipeline segment* is also absent in the PRIA. The PRIA asserts that because SCCDAs are not the "typical[]" method for assessing stress corrosion cracking, its new standards would not "impose a significant additional cost burden on pipeline operators." JA__ (PRIA 71). That is insufficient. PHMSA never estimated the additional costs of tripling the number of excavations each SCCDA must perform when those

assessments are necessary. Moreover, Section 60102(b)(3)(B) requires PHMSA to estimate the *benefits*, as well as costs, of its new standard, and PHMSA never attempts to do so. PHMSA's change from requiring three excavations per SCC segment to three excavations per covered pipeline segment carried "no economic data or analysis" for the public "to review and analyze." *GPA Midstream*, 67 F.4th at 1194. The pipeline safety laws "require more." *Id.* at 1196.

Fourth, the safety-factor-5 standard—along with the entirety of Section 192.712(c)—is wholly missing from the PRIA. *See generally* JA__-__ (PRIA 1-182). PHMSA first suggested changing its assessment methods at a March 2018 GPAC meeting, JA__-__ (PHMSA Slide Presentation to GPAC 146-153), years after issuing its NPRM. If PHMSA wanted to require fatigue life assessments to use a safety factor of 5, "then it should have said so in time for peer review and public comment." *GPA Midstream*, 67 F.4th at 1197.

To be clear, PHMSA also failed to perform a cost-benefit analysis for these standards when issuing its Final Rule years later. *See infra* Argument III. But even if the Final Rule included such an analysis, PHMSA would still have violated Section 60102(b)(3)(B)'s requirement for a *preliminary* cost-benefit assessment. As *GPA Midstream* teaches, PHMSA is not permitted to "sidestep[] the process of public deliberation required by law," regardless of what cost-benefit analysis its final rule includes. 67 F.4th at 1197.

Finally, INGAA was prejudiced by PHMSA's failure to offer a preliminary cost-benefit assessment because it "has something useful to say" about how the costs of these four contested standards outweighed the benefits. *Id.* at 1199. It explained that the HF-ERW standard will impose significant costs and provide almost no safety benefit because metal loss in HF-ERW seams is not immediately dangerous. JA__-__ (INGAA Comments 91-92). It wrote that there is limited benefit to imposing a safety margin greater than 1.1-times MAOP because other regulations effectively prohibit pipelines from exceeding their MAOPs. JA__-__ (Petition for Reconsideration 7-8). It explained that PHMSA's new SCCDA-per-pipeline-segment standard could triple the number, and associated costs, of excavations. JA__-__ (Petition for Reconsideration 26-27). And lastly, it told PHMSA that the safety-factor-5 standard "significantly increase[s]" costs by more than doubling the number of required reassessments "without any discernable safety benefit." JA__ (Petition for Reconsideration 15).

B. For the corrosive-constituent standard, PHMSA failed to consider GPAC's contrary recommendation.

Section 60102(b)(2)(G) requires PHMSA to consider GPAC's "comments and recommendations." PHMSA's corrosive-constituent standard failed to do so.

PHMSA's 2016 NPRM proposed to add Section 192.478 to impose new monitoring requirements on any pipeline with "potentially corrosive constituents in the gas," requiring operators to "evaluate the partial pressure of each corrosive

constituent." JA__ (NPRM, 81 Fed. Reg. at 20,830) (quoting 49 C.F.R. § 192.478(a)). At the June 2017 GPAC meeting on the proposed standard, GPAC recommended that PHMSA "[l]imit the applicability of paragraph (a) [in § 192.478] to the transportation of corrosive gas." JA__ (GPAC Meeting Final Voting Slides 9). Among other things, GPAC's members explained that the new standard would add little benefit because pipelines already monitor water levels, a key ingredient for corrosive gas. JA__-__ (GPAC Meeting Transcript 210-211 (June 6, 2017)) (Zamarin Statement). GPAC members further requested that PHMSA provide data supporting the proposal. JA__, __ (GPAC Meeting Transcript 275, 278 (Jan. 11, 2017) (Campbell and Zamarin Statements)).

But "PHMSA plowed ahead anyway." *GPA Midstream*, 67 F.4th at 1194. As enacted, Section 192.478(a) imposed monitoring requirements on any pipeline with "corrosive constituents in the gas,"[13] and included the identical requirement to "evaluate the partial pressure of each corrosive constituent." JA__ (Final Rule, 87 Fed. Reg. at 52,270). Neither limits monitoring requirements to "corrosive gas."

[13] In Section 1972.478(a)'s first sentence, PHMSA's final rule dropped the word "potentially" from a pipeline's requirement to monitor "corrosive constituents." *See* JA__ (Final Rule, 87 Fed. Reg. at 52,270). That change is meaningless. "Corrosive constituents" and "potentially corrosive constituents" are both, by themselves, harmless and thus only have the *potential* to corrode. PHMSA's own RIA continued to refer to a pipeline's new obligation to monitor "potentially corrosive constituents," JA__ (RIA 14), underscoring that the NPRM's proposed monitoring requirement was never changed.

PHMSA never explained why it rejected GPAC's recommendation. Instead, the preamble to PHMSA's Final Rule stated, "Based on the comments received [from GPAC and others], PHMSA is revising the scope of proposed § 192.478 in this final rule to limit its applicability to the transportation of corrosive gas." JA__ (Final Rule, 87 Fed. Reg. at 52,238). But it never actually did. PHMSA's letter denying reconsideration confirms that. It acknowledges that Section 192.478(a)'s new monitoring requirements extend beyond "corrosive gas," and into "a variety of gas streams" that contain the "constituents identified in Section 192.478(a)." JA__ (PHMSA Letter 10).

PHMSA was required—and failed—to "consider" GPAC's recommendation to limit Section 192.478(a)'s monitoring requirements to corrosive gas. 49 U.S.C. § 60102(b)(2)(G). PHMSA's prefatory (and unfulfilled) statement that it will implement that change, without ever actually implementing it, does not count as consideration. *See Natural Res. Def. Council v. EPA*, 559 F.3d 561, 564-565 (D.C. Cir. 2009) (referring to agency's statements in the rule's preamble, but not reflected in the rule itself, as "a legal nullity").

PHMSA's denial of reconsideration failed to correct that error. It suggested that by including the words "where applicable" and "as necessary," PHMSA somehow responded to GPAC's recommendations. JA__ (PHMSA Letter 10); *see also supra* p. 12 n. 3. Arguably, those "qualifications," *id.*, confirmed that

pipelines are not required to mitigate the effects of corrosive constituents, which makes sense: Corrosive constituents are, by themselves, harmless. But neither PHMSA's Final Rule nor its denial of reconsideration implemented GPAC's recommendation to limit a pipeline's *monitoring* requirements to "corrosive gas." JA__ (GPAC Meeting Final Voting Slides 9).

After receiving GPAC's recommendation to limit Section 192.478(a)'s monitoring requirements to corrosive gas, PHMSA had to either change that requirement or reasonably explain why it was departing from GPAC's recommendation to change it. PHMSA did neither, its omission prejudiced INGAA, and this Court should set Section 192.478(a) aside.

II. PHMSA FAILED TO PROPERLY NOTICE THE SAFETY-FACTOR-5 AND 1.25-TIMES-MAOP STANDARDS.

A final regulation "violates the APA[] if it is not a 'logical outgrowth' of the agency's proposed regulations." *Association of Private Sector Colls. & Univs. v. Duncan*, 681 F.3d 427, 442 (D.C. Cir. 2012). Both the safety-factor-5 and 1.25-times-MAOP standards fail that test.

First, PHMSA's safety-factor-5 standard fails the logical-outgrowth test because the NPRM gave "no indication" that it was considering imposing any such standard. *CSX Transp.*, 584 F.3d at 1081. This standard was first discussed (as a *safety-factor-2* requirement) during the March 2018 GPAC meeting. JA__-__ (PHMSA Slide Presentation to GPAC 149). By never alluding to safety factors or

even fatigue life assessments more broadly in its NPRM, PHMSA comes nowhere close to satisfying the APA's demand. *See Daimler Trucks N. Am. LLC v. EPA*, 737 F.3d 95, 100 (D.C. Cir. 2013) (agency failed the logical outgrowth test because its NPRM "offered no indication that it was contemplating" the changes the final rule made to the C.F.R.); *Duncan*, 681 F.3d at 461 (final rules regulating "distance education" were not a logical outgrowth of the proposed rules, which did not "specifically address" distance education).

Second, an agency fails the logical-outgrowth test where its final rule is a "complete turnaround from the NPRM." *CSX Transp.*, 584 F.3d at 1082. PHMSA's 1.25-times-MAOP standard took that forbidden path. The NPRM was clear: PHMSA was "not proposing to change" its 1.1-times-MAOP threshold for any anomalies, including cracks. JA__ (NPRM, 81 Fed. Reg. at 20,756). But the Final Rule did just that, raising its threshold to immediately repair cracks to 1.25-times-MAOP. JA__-__ (Final Rule, 87 Fed. Reg. at 52,277-78).

That maneuver is on all fours with what this Court rejected in *International Union, United Mine Workers of America v. MSHA*, 407 F.3d 1250, 1259-60 (D.C. Cir. 2005). In *UMW*, the preamble of the agency's proposed rule stated it would "not include a maximum velocity air cap" in its underground coal mine ventilation standard. *Id.* at 1260. But then the final rule "set a velocity cap of 500 feet per minute." *Id.* at 1252. This Court concluded that the final rule was not a logical

outgrowth of the proposed rule because, given the agency's disavowal, there was no way for "interested parties to realize that [the Secretary] would consider abandoning her proposed regulatory approach." *Id.* at 1260. The same applies here. After PHMSA expressly stated that it would not change its 1.1-times-MAOP standard, interested parties, including INGAA, had no way of knowing that PHMSA was actually "consider[ing] abandoning" it for cracks. *Id.*; *Environmental Integrity Proj. v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (agencies may not "use the rulemaking process to pull a surprise switcheroo on regulated entities"); *see also Allina Health Servs. v. Sebelius*, 746 F.3d 1102, 1108 (D.C. Cir. 2014) (similar).

It makes no difference that these changes were discussed at a GPAC meeting years after the NPRM. As this Court explained in *Duncan*, "the agency must *itself* provide notice of a regulatory proposal," regardless of what other comments or proposals it receives. 681 F.3d at 462. PHMSA's rulemakings are subject to the requirements of *both* the "pipeline safety laws" and "the APA." *GPA Midstream*, 67 F.4th at 1196. The APA's requirement that the NPRM provide "[n]otice of agency action" in a proposed rulemaking is clear. *Daimler Trucks*, 737 F.3d at 95. That requirement is separate from PHMSA's other duties to allow GPAC to review its proposals and to consider GPAC's recommendations. 49 U.S.C. § 60102(b)(2)(G), (b)(4)(A). PHMSA's final safety-factor-5 standard and 1.25-

times-MAOP standard were not logical outgrowths of the standards PHMSA proposed in its NPRM. Those standards should be vacated for this reason alone. *See Allina Health*, 746 F.3d at 1110 ("deficient notice is a 'fundamental flaw' that almost always requires vacatur" (quoting *Heartland Reg'l Med. Ctr. v. Sebelius*, 566 F.3d 193, 199 (D.C. Cir. 2009)).

III. ON THE MERITS, ALL OF PHMSA'S CONTESTED STANDARDS ARE UNREASONABLE AND SHOULD BE VACATED.

PHMSA's final standards must be based on a "reasoned determination" that the benefits "justify" their costs. 49 U.S.C. § 60102(b)(5); *see also GPA Midstream*, 67 F.4th at 1199-1201. Because the final versions of PHMSA's five contested standards *all* violated that requirement, its standards are unreasonable.

That substantive error is distinct from PHMSA's procedural failure to offer a preliminary cost-benefit in its PRIA. *See supra* Argument I.A. 49 U.S.C. § 60102(b)(3)(B) requires PHMSA to "identify the costs and benefits associated with the *proposed* standard." (emphasis added); *see also GPA Midstream*, 67 F.4th at 1196-98 (faulting PHMSA for failing to follow this procedural requirement). Separately, Section 60102(b)(5) requires any *final* standard to be based on the agency's "reasoned determination that the benefits, including safety and environmental benefits, of the intended standard justify its costs." *See also GPA Midstream*, 67 F.4th at 1199-1201 (faulting PHMSA for failing to follow this substantive requirement). Here, PHMSA flouted each of these two distinct

statutory requirements (one procedural, one substantive)—just as it did in *GPA Midstream*.

Several of PHMSA's contested standards have additional substantive defects. The HF-ERW standard fails to consider the "probability" of metal loss causing failure in HF-ERW seams, as *GPA Midstream* requires. *Id.* at 1201. The 1.25-times-MAOP standard fails to explain why 1.25-times is the right number, focusing exclusively—and unreasonably—on why 1.1-times-MAOP is the *wrong* number. And PHMSA's defense that pipelines may apply for an exemption from its safety-factor-5 standard is foreclosed under *GPA Midstream*. *Id.* at 1199. Any one of these additional reasons independently renders the contested standards unreasonable.

A. The corrosion-constituent standard failed to consider costs.

When PHMSA first proposed its corrosion-constituent standard, it estimated a total cost of $400,000, *see* JA__ (PRIA 91), and total benefits of $900,000, JA__-__ (PRIA 126-127). INGAA informed PHMSA that its cost estimate was wildly low; the proposed corrosion-constituent standard, INGAA calculated, would cost more than $75,000,000. JA__ (INGAA Comments 204); JA__ (INGAA Cost Analysis 35). INGAA informed PHMSA that these requirements "will increase costs without increasing safety." JA__ (INGAA Comments 112).

PHMSA did not address that analysis. Nor did it attempt to defend its preliminary cost-benefit assessment. PHMSA simply disclaimed the responsibility to conduct any cost-benefit analysis *at all*. PHMSA offered two reasons in support, and neither has merit.

First, PHMSA's final RIA asserted that because it "assume[s]" most pipelines "already have the infrastructure in place to comply" with its corrosive-constituent standard, the costs are not worth fully analyzing. JA__ (RIA 25); JA__ (PHMSA Letter 10) (asserting the same assumption). For starters, PHMSA's assumption is contradicted by the record. INGAA told PHMSA that its corrosion-constituent standard would require new equipment to be installed at 830 receipt points, JA__ (INGAA Cost Analysis 35); *see also* JA__-__ (INGAA Comments 203-204). PHMSA never responded to, much less incorporated, INGAA's on-the-ground figures. By relying on the same unsupported (and now contradicted) assumption, PHMSA committed a textbook case of unreasonable decisionmaking. *See Motor Vehicle Mfrs. of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (action is arbitrary and capricious if agency "offered an explanation for its decision that runs counter to the evidence before the agency"); *Genuine Parts Co. v. EPA*, 890 F.3d 304, 308 (D.C. Cir. 2018) (vacating EPA's final rule where agency "ignored evidence undercutting its conclusion"); *Sorenson*

Commc'ns, 755 F.3d at 708 (vacating rule that relied on "unsubstantiated conclusion[s]").

Even assuming PHMSA's assumption was true, its explanation would still violate Section 60102(b)(5)'s requirement that the rule's benefits justify its costs. In *GPA Midstream*, PHMSA also asserted that because "few gathering pipelines will be subject to [its new] rule," a full cost-benefit analysis was unnecessary. 67 F.4th at 1200. This Court held that was "inadequate." *Id.* "The relevant question under the law," this Court explained, is "whether the benefits of [PHMSA's regulation] justify the costs," and PHMSA is required to "answer[]" it. *Id.* Asserting that the costs of the corrosion-constituent standard are negligible because only a fraction of pipelines will be affected fails to measure the standard's "benefits" against its "costs," as Section 60102(b)(5) demands. *Id.*

Second, PHMSA asserted that "precisely how much th[e] compliance costs are" for its new corrosion-constituent standard was too "hard to determine because of uncertainties regarding operators' compliance strategies with respect to existing regulations." JA__ (RIA 27). That is insufficient. Under Section 60102(b)(5), PHMSA must either conduct the cost-benefit analysis or offer a reasonable explanation for why costs and benefits "cannot reasonably be quantified." *GPA Midstream*, 67 F.4th at 1200; *see also Chamber of Commerce of U.S. v. SEC*, 412 F.3d 133, 143-144 (D.C. Cir. 2005) (rejecting as unreasonable the Commission's

explanation for why it could not quantify the costs of its new rule). PHMSA did neither.[14] It did not perform a cost-benefit analysis, and PHMSA's explanation for why quantitative analysis was infeasible ignores that it *already* provided a preliminary cost-benefit assessment for this standard. *See* JA__-__ (PRIA 88-91); *supra* pp. 9-10. INGAA similarly provided its own competing analysis, complete with precise figures and numeric calculations. *See* JA__ (INGAA Cost Analysis 35); *supra* pp. 10-11. PHMSA never explains why the costs and benefits of its corrosive-constituents standard could be quantified before, but cannot be quantified now. PHMSA's explanation is unreasonable, and this Court should "not defer to it." *GPA Midstream*, 67 F.4th at 1199.

B. The HF-ERW standard failed to quantify or consider costs, and separately, failed to consider the probability of pipeline failure.

PHMSA's HF-ERW standard violates Section 60102(b)(5)'s cost-benefit assessment requirement for two reasons.

First, the standard fails to quantify, or even reference, the costs of making metal loss in HF-ERW seams an immediate repair condition. INGAA's comments on PHMSA's proposed standard underscored that "PHMSA has not explained or

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[14] In *GPA Midstream*, PHMSA similarly pointed to "the difficulty of quantifying the benefits of the rule in terms of avoided incidents and accidents." Final Brief for Respondents at 46, *GPA Midstream Ass'n v. U.S. Dep't of Transp.* (D.C. Cir. 2023) (No. 22-1148). This Court rejected that rationale in *GPA Midstream*, 67 F.4th at 1200, and should do so again here.

provided data to support its proposal to treat metal loss associated with high-frequency electric resistance welded seams as an immediate repair condition." JA__-__ (INGAA Comments 91-92). And when the Final Rule proved identical to the proposed standard in this respect, INGAA's petition for reconsideration again explained that PHMSA had failed to account "for the costs and benefits of this provision." JA__ (Petition for Reconsideration 18).

Even with that prodding, PHMSA has never done so. PHMSA's Final Rule simply states that "historically, longitudinal seams that are formed by direct-current welding, low-frequency or high-frequency electric resistance welding . . . are more likely to fail. Therefore, PHMSA has determined that more stringent repair criteria are necessary." JA__ (Final Rule, 87 Fed. Reg. at 52,252). PHMSA offered no further data or analysis.

PHMSA's final RIA, meanwhile, makes a blanket assertion about all of Section 192.933(d)(1)'s revisions, which include new immediate repair requirements for "metal loss defects, stress corrosion cracking, and metal-loss affecting a detected longitudinal seam [i.e., HF-ERW and LF-ERW], and selective seam corrosion." JA__-__ (RIA 35-36). According to PHMSA, all these immediate repair requirements were already in place, so they "imposed [no] additional cost burden on pipeline operators." *Id.* Specifically, PHMSA said that Section 192.933(d)(1) had already required operators to follow "ASME/ANSI

B31.8S," an industry safety manual, and that its new rule simply makes requirements in that safety manual "explicit[]." *Id.*

INGAA told PHMSA that was wrong, at least with respect to HF-ERW. Its July 2016 comment letter explained that metal loss on HF-ERW weld seams is "not considered an injurious condition under any known industry standard." JA__ (INGAA Comments 91). INGAA further informed PHMSA that its position was "inconsistent with B31.8S-2004, Section 7.2.1," the same industry manual that PHMSA pointed to, because that manual "does not treat high-frequency electric resistance welded seams as an immediate repair condition." *Id.* PHMSA never responded. Because PHMSA's premise that pipelines were already treating metal loss in HF-ERW as an immediate repair condition is both wrong and contradicted in the record, PHMSA's continued reliance on it was unreasonable. *See State Farm*, 463 U.S. at 43; *Genuine Parts*, 890 F.3d at 308; *Sorenson Commc'ns*, 755 F.3d at 708.[15]

A proper Section 60102(b)(5) assessment would have estimated how many miles of HF-ERW seam would experience metal loss, how expensive each mile

[15] PHMSA's denial of reconsideration also fails to quantify, or even consider, the costs of its new HF-ERW rule. JA__ (PHMSA Letter 12). It simply asserts that there are *benefits* to making metal-loss in HF-ERW pipe seams an immediate repair condition because such pipe is "vulnerab[le]" to failure. *Id.* PHMSA' letter offers no figures or analysis of the *costs*.

would be to replace, and the number of pipeline failures it would avert (or other benefits it would provide). *See* JA__-__ (RIA 37-41) (performing that analysis for other standards). Without such a quantitative analysis, PHMSA was required to "explain why any unquantified benefits cannot reasonably be quantified." *GPA Midstream*, 67 F.4th at 1200. PHMSA did neither.

Second, PHMSA's expert reports—referenced for the first time in its denial of reconsideration—do not save its HF-ERW standard. JA__-__ (PHMSA Letter 12-13). For starters, agencies are prohibited from backfilling a final rule's record with "entirely new information critical" to the agency's determination. *American Pub. Gas Ass'n v. U.S. Dep't of Energy*, 72 F.4th 1324, 1338 (D.C. Cir. 2023). And here, PHMSA's overdue reports are "critical" because they are the only materials PHMSA has *ever* used to justify its HF-ERW standard. *Window Covering Manufacturers Ass'n v. Consumer Prod. Safety Comm'n*, 82 F.4th 1273, 1283 (D.C. Cir. 2023) (supplemental materials were "critical" "because no usable information was provided to the public" during the rulemaking); *American Public Gas Ass'n*, 72 F.4th at 1338 ("new studies and datasets" are critical where they do more than "address[] alleged deficiencies in [any] pre-existing data") (quotation marks omitted).

PHMSA's after-the-fact reliance on these reports is also substantively unreasonable. That HF-ERW *can* theoretically fail, as these reports claim—*but see*

supra p. 18 (noting a zero failure rate from 2010 to 2017)—does not mean that it is reasonable to subject HF-ERW welds to immediate-repair requirements. *GPA Midstream* reaffirmed that PHMSA must also consider "the probability" of a failure. 67 F.4th at 1201. By all accounts, LF-ERW is much more *likely* to experience metal-loss weld failures than HF-ERW. Even PHMSA's letter denying reconsideration states that seam failures in HF-ERW occur "admittedly at a lower rate than LF-ERW pipe." JA__ (PHMSA Letter 12). Yet PHMSA asserts that HF-ERW pipe can be subject to same immediate-repair requirements as LF-ERW pipe simply because it "may also be prone to defects." JA__ (PHMSA Letter 13). That is insufficient. PHMSA's cost-benefit assessment must incorporate the probability that defects in HF-ERW pipe exist and that they will result in actual harm. PHMSA failed to do so, violating *GPA Midstream*'s clear command. 67 F.4th at 1201 (cost-benefit analysis may not "ignore the probability of a rupture").

PHMSA's post-Final-Rule reliance on these reports was unreasonable, and its HF-ERW standard should be vacated.

C. The 1.25-times-MAOP standard failed to consider costs and benefits and, separately, failed to explain why 1.25-times-MAOP strikes the right balance.

PHMSA's 1.25-times-MAOP standard should be set aside for two reasons.

First, PHMSA's Final Rule and final RIA do not mention this standard's costs or benefits at all. PHMSA acknowledges that in footnote 11 of its letter

denying reconsideration. *See* JA__ n.11 (PHMSA Letter 4 n.11). PHMSA's failure to contemporaneously offer a "reason[]" for why the benefits of its 1.25-times-MAOP standard justify its costs is sufficient in itself to set it aside. *Department of Homeland Sec. v. Regents or Univ. of Calif.*, 140 S. Ct. 1891, 1909 (2020) ("An agency must defend its actions based on the reasons it gave when it acted.").

PHMSA's letter denying reconsideration argues that there is "no basis in statute or regulation" for it to perform a standard-specific cost-benefit analysis. JA__ n.11 (PHMSA Letter 4 n.11). But Section 60102(b)(5) requires just that. *See GPA Midstream*, 67 F.4th at 1200 (explaining that the same statutory provision requires a "thorough" cost-benefit assessment for each proposed standard). PHMSA issued its reconsideration-denial letter one month before this Court decided *GPA Midstream*, so it must not have known that it was walking straight into reversible legal error.

Next, PHMSA's footnote states that a "cost-effectiveness" analysis for its 1.25-MAOP-requirement would be "[im]practicable" because PHMSA's "regulatory regime" is too "comprehensive and highly technical." JA__ n.11 (PHMSA Letter 4 n.11). *GPA Midstream* rejected that, too. This Court reiterated that because cost-benefit analysis always "requires making projections," PHMSA must do more than make broad assertions about the unavailability of "detailed"

cost-benefit analyses. *GPA Midstream*, 67 F.4th at 1200 (citation omitted). If PHMSA's technical-regulations-are-too-technical rationale were valid, then PHMSA would almost always be able to bypass Section 60102(b)(5)'s mandate—just as it attempted, and failed, to do in *GPA Midstream.*

Moreover, PHMSA makes no effort to explain why such projections were feasible for several of its proposed standards, but not for its 1.25-times-MAOP standard. For other changes to its repair criteria, PHMSA estimates the miles of pipeline impacted by various standards, the cost of performing repairs, and the expected benefits. JA__-__ (RIA 37-41). PHMSA's failure to do so here—coupled with its failure to reasonably explain *why* calculating such costs was impracticable—was unreasonable.

Second, to pass arbitrary-and-capricious review, PHMSA must state why it selected its "*specific*" 1.25-times-MAOP threshold, not simply why it rejected 1.1-times-MAOP. *Bluewater Network*, 370 F.3d at 21. PHMSA flunks that test, as well. Its Final Rule simply states that 1.1-times-MAOP was insufficiently "conservative" (or "inadequate") without explaining why 1.25 times MAOP is the right threshold. JA__ (Final Rule, 87 Fed. Reg. at 52,248).

That explanation echoes the reasoning that this Court rejected in *Bluewater Network*, 370 F.3d at 21. There, the EPA concluded that advanced emissions technologies could be "applied to no more than 70% of new snowmobiles by

2012" because, the agency said, "snowmobile manufacturers are 'resource constrained.' " *Id.* at 6, 21. This Court held that was unreasonable because the same rationale "could just as well support" any standards "corresponding to 30% or 100% application in that time frame." *Id.* at 21. This Court held that the EPA failed to explain how it "arrived at [its] *specific* [70%] conclusion." *Id.*

The same is true here. PHMSA's explanation that 1.1-times-MAOP was not "conservative" enough, JA__ (Final Rule, 87 Fed. Reg. at 52,248), could justify any threshold between 1.1 and 1.25-times-MAOP, or for that matter, numbers far exceeding 1.25-times-MAOP. Because PHMSA never explained its "*specific* conclusion" that 1.25-times-MAOP strikes the right balance, its decision to impose that requirement was unreasonable. *Bluewater Network*, 370 F.3d at 21.

PHMSA's letter denying reconsideration posits, without further analysis, that the 1.25-times figure was "carefully selected" and "calibrated." JA__ (PHMSA Letter 3). That justification not only came too late, *Regents of Univ. of Calif.*, 140 S. Ct. at 1909; it is also insufficient. To pass arbitrary-and-capricious review, PHMSA must explain how and why the 1.25-times-MAOP figure was "carefully" "calibrated"—not just offer conclusory assertions saying that it was. *See Environmental Health Tr. v. FCC*, 9 F.4th 893, 909 (D.C. Cir. 2021) ("[A] conclusory and unexplained statement is not the 'reasoned' explanation required by the APA."); *International Union, United Mine Workers v. MSHA*, 626 F.3d 84,

93 (D.C. Cir. 2012) (rejecting a "conclusory statement" that was "unsupported by the rulemaking record").

PHMSA failed to explain why the benefits of its 1.25-MAOP standard justified its costs, and separately, how it arrived at its final figure; this rule, too, should be vacated.

D. The SCCDA-pipeline-segment standard failed to consider costs.

PHMSA's new standard requiring that SCCDAs conduct three excavations per covered pipeline segment, instead of three per SCC segment, fails for the same reason. Because "it is not apparent just how [PHMSA] went about weighing the benefits against the costs" of this new requirement, this Court should set it aside. *GPA Midstream*, 67 F.4th at 1200.

PHMSA's final RIA mentions its new SCCDA standards (codified at Section 192.929) twice. At page 13, it states that Section 192.929 incorporates industry standards, referred to as NACE SP0206 and NACE SP0204. JA__ (RIA 13). Then, at page 19, PHMSA states that Section 192.929's new requirements impose "negligible" incremental costs because all they do is incorporate these "consensus industry standards." JA__ (RIA 19).

But Section 192.929(b)(3), which codifies the contested SCCDA-pipeline-segment standard, does more than that. It states, "*[i]n addition to NACE SP0204*, the plan's procedures for direct examination must provide for an operator

conducting a minimum of three direct examinations for SCC within the covered pipeline segment." JA__ (Final Rule, 87 Fed. Reg. at 52,276) (emphasis added). On the regulation's face, PHMSA's requirement for three examinations per covered pipeline segment does not just incorporate industry standards; it supplements them. PHMSA has never explained how the "benefits" of that new requirement "justify its costs." 49 U.S.C. § 60102(b)(5).

INGAA's petition for reconsideration explained that PHMSA's late-breaking change to requiring three excavations per covered pipeline segment could triple the number of required excavations, and that PHMSA failed to account for those additional costs in its final RIA.[16] JA__-__ (Petition for Reconsideration 26-27). PHMSA did not perform any cost-benefit assessment to justify *any* number of required excavations. *See* JA__ (RIA 19). That omission is fatal. PHMSA's requirement that each SCCDA perform three excavations per covered pipeline segment should be vacated.

[16] INGAA can proffer that requiring three excavations per covered pipeline segment, as opposed to per SCC segment, produces *no* additional benefit. INGAA was unable to present its own cost-benefit analysis during rulemaking because PHMSA had not noticed this change in its NPRM, or otherwise subjected it to "peer review" and public comment. *GPA Midstream*, 67 F.4th at 1196.

E. The safety-factor-5 standard failed to consider costs and impermissibly relies on waivers.

Finally—and yet again—PHMSA failed to consider costs of requiring fatigue life analysis to use a safety factor of 5, instead of the GPAC-approved safety factor of 2. PHMSA's Final Rule and final RIA contain no analysis of this new requirement. The final RIA does not include the word "fatigue." *See generally* JA__-__ (RIA 1-49). While the final RIA purports to analyze the costs and benefits of changes to Sections 192.712(b) and 192.712(d), JA__ (RIA 37), the safety-factor-5 standard is codified in Section 192.712(c), JA__ (Final Rule, 87 Fed. Reg. at 52,271), and the RIA does not mention that provision.

INGAA's petition for reconsideration explained that PHMSA's safety-factor-5 standard "significantly increase[s]" costs while providing no "discernable safety benefit." JA__ (Petition for Reconsideration 15). It requested that PHMSA revert back to the safety-factor-2 requirement that GPAC endorsed because "the record contains no basis" for PHMSA's safety-factor-5 standard and because PHMSA failed to analyze the "safety benefit[s]" and costs of its new standard. *Id.*

PHMSA refused for two main reasons. First, it responded that the safety-factor-5 standard was justified by an American Petroleum Institute report—never before referenced—that recommended safety factors between 2 and 5. JA__ (PHMSA Letter 8). But where, as here, a report's factual material is "critical" to the agency's formal decisionmaking, the agency must "test[]" that study "through

exposure to public comment." *Chamber of Commerce. of U.S. v. SEC*, 443 F.3d 890, 900 (D.C. Cir. 2006); *see also supra* p. 53.

The API study is the only material that PHMSA has ever cited to support its safety-factor-5 standard, and PHMSA adopted, without qualification, the report's upper limit. JA__ (PHMSA Letter 8). It was critical, and PHMSA's failure to subject it to notice and comment warrants vacatur. *See Window Covering Mfrs. Ass'n*, 82 F.4th at 1283; *American Pub. Gas Ass'n*, 72 F.4th at 1338.

Second, PHMSA asserted that operators could "seek PHMSA permission" to go beneath the default safety-factor-5 standard. JA__ (PHMSA Letter 9). In *GPA Midstream*, PHMSA made the same argument, and this Court rejected it. This Court held that relying on PHMSA's discretionary waivers would "impermissibly shift the burden of proof to the petitioners and other operators." *GPA Midstream*, 67 F.4th 1199. Then, and now, PHMSA's waiver argument "must [be] reject[ed]." *Id.*

* * *

Each of the challenged standards offers multiple paths to vacatur. The "ordinary practice is to vacate unlawful agency action," *United Steel v. MSHA*, 925 F.3d 1279, 1287 (D.C. Cir. 2019), and this Court should follow that practice here. The "deficiencies" in the five contested standards are "serious[]" and vacatur will not "cause disruption." *Id.* (citation omitted).

To recap: The corrosion-constituent standard should be vacated because PHMSA failed to consider GPAC's recommendation or because the two reasons PHMSA gave for not conducting a targeted final cost-benefit assessment are unreasonable.

The HF-ERW standard should be vacated because PHMSA did not conduct a preliminary cost-benefit assessment, because its Final Rule failed to consider costs, or because its after-the-fact justification failed to consider the probability that HF-ERW pipe would fail.

The 1.25-times-MAOP standard should be vacated because PHMSA did not conduct a preliminary cost-benefit assessment, because PHMSA did not provide proper notice in its NPRM, because PHMSA's Final Rule did not consider costs, or because PHMSA offered no reasonable explanation for why 1.25-times-MAOP strikes the right balance between additional costs and safety benefits.

The SCCDA-pipeline-segment standard should be vacated because PHMSA did not conduct a preliminary cost-benefit assessment or because its Final Rule failed to consider costs and benefits.

Finally, the safety-factor-5 standard should be vacated because PHMSA did not conduct a preliminary cost-benefit assessment, because PHMSA did not provide proper notice in its NPRM, because PHMSA did not adequately explain

why the benefits of a safety factor of 5 justified the costs, or because PHMSA improperly relied on the theoretic availability of waivers to justify this standard.

INGAA, however, does not request vacatur of the entire Final Rule. It requests that this Court sever the Final Rule and issue a "[l]imited [v]acatur," similar to the remedy this Court ordered in *GPA Midstream*. 67 F.4th at 1201-02. INGAA requests that this Court sever and vacate Section 192.478 (corrosion-constituent standard), Sections 192.714(d)(1)(v)(C) and 192.933(d)(1)(v)(C) (1.25-times-MAOP standard), Section 192.929(b)(3) (SCCDA-pipeline-segment standard), and Section 192.712(c)(9) (safety-factor-5 standard), and that it strike the words "or high-frequency" from 49 C.F.R. § 192.714(d)(1)(iv) and § 192.933(d)(1)(iv) (HF-ERW standard). Because these standards "operate[] entirely independently of one another," they should be severed from the Final Rule and vacated. *American Petroleum Inst. v. EPA*, 862 F.3d 50, 71 (D.C. Cir. 2017) (citation omitted).

CONCLUSION

The petition for review should be granted, and the contested standards should be severed and vacated.

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

1. This document complies with the type-volume limit set by this Court's briefing order because, excluding the parts of the document exempted by Fed. R. App. P. 32(f), this document contains 12,974 words.

2. This document complies with the typeface requirements of Fed. R. App. P. 32(a)(5) and the type-style requirements of Fed. R. App. P. 32(a)(6) because this document has been prepared in a proportionally spaced typeface using Microsoft Word 2010 in 14-point Times New Roman.

/s/ Catherine E. Stetson
Catherine E. Stetson

ADDENDUM

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**The amended versions of these regulations have not yet been published in the Code of Federal Regulations. These regulations have therefore been excerpted from www.ecfr.gov, an authoritative site jointly administered by the Office of the Federal Register and the U.S. Government Publishing Office.*

new equipment or technologies that are inserted into pipelines to detect anomalies;

''(3) internal inspection and leak detection technologies, including detection of leaks at very low volumes;

''(4) methods of analyzing content of pipeline throughput;

''(5) pipeline security, including improving the real-time surveillance of pipeline rights-of-way, developing tools for evaluating and enhancing pipeline security and infrastructure, reducing natural, technological, and terrorist threats, and protecting first response units and persons near an incident;

''(6) risk assessment methodology, including vulnerability assessment and reduction of third-party damage;

''(7) communication, control, and information systems surety;

''(8) fire safety of pipelines;

''(9) improved excavation, construction, and repair technologies;

''(10) corrosion detection and improving methods, best practices, and technologies for identifying, detecting, preventing, and managing internal and external corrosion and other safety risks; and

''(11) other appropriate elements.

The results of activities carried out under paragraph (10) shall be used by the participating agencies to support development and improvement of national consensus standards.

''(d) PROGRAM PLAN.—

''(1) IN GENERAL.—Not later than 1 year after the date of enactment of this section [Dec. 17, 2002], the Secretary of Transportation, in coordination with the Secretary of Energy and the Director of the National Institute of Standards and Technology, shall prepare and transmit to Congress a 5-year program plan to guide activities under this section. Such program plan shall be submitted to the Technical Pipeline Safety Standards Committee and the Technical Hazardous Liquid Pipeline Safety Standards Committee for review, and the report to Congress shall include the comments of the committees. The 5-year program plan shall be based on the memorandum of understanding under subsection (b) and take into account related activities of other Federal agencies.

''(2) CONSULTATION.—In preparing the program plan and selecting and prioritizing appropriate project proposals, the Secretary of Transportation shall consult with or seek the advice of appropriate representatives of the natural gas, crude oil, and petroleum product pipeline industries, utilities, manufacturers, institutions of higher learning, Federal agencies, pipeline research institutions, national laboratories, State pipeline safety officials, labor organizations, environmental organizations, pipeline safety advocates, and professional and technical societies.

''(3) ONGOING PIPELINE TRANSPORTATION RESEARCH AND DEVELOPMENT.—

''(A) IN GENERAL.—After the initial 5-year program plan has been carried out by the participating agencies, the Secretary of Transportation, in coordination with the Director of the National Institute of Standards and Technology, as appropriate, shall prepare a research and development program plan every 5 years thereafter and shall transmit a report to Congress on the status and results-to-date of implementation of the program every 2 years. The biennial report shall include a summary of updated research needs and priorities identified through the consultation requirements of paragraph (2).

''(B) CONSULTATION.—The Secretary shall comply with the consultation requirements of paragraph (2) when preparing the program plan and in the selection and prioritization of research and development projects.

''(C) FUNDING FROM NON-FEDERAL SOURCES.—The Secretary shall ensure at least 30 percent of the costs of program-wide research and development activities are carried out using non-Federal sources.

''(e) REPORTS TO CONGRESS.—Not later than 1 year after the date of enactment of this Act [Dec. 17, 2002], and annually thereafter, the heads of the participating agencies shall transmit jointly to Congress a report on the status and results to date of the implementation of the program plan prepared under subsection (d).

''(f) PIPELINE INTEGRITY PROGRAM.—Of the amounts available in the Oil Spill Liability Trust Fund established by section 9509 of the Internal Revenue Code of 1986 (26 U.S.C. 9509), $3,000,000 shall be transferred to the Secretary of Transportation, as provided in appropriation Acts, to carry out programs for detection, prevention, and mitigation of oil spills for each of the fiscal years 2012 through 2015.

''(g) PARTICIPATING AGENCIES DEFINED.—In this section, the term 'participating agencies' means the Department of Transportation, the Department of Energy, and the National Institute of Standards and Technology.''

DEFINITIONS

Pub. L. 112–90, §1(c), Jan. 3, 2012, 125 Stat. 1904, provided that:

''(1) APPLICABILITY OF CHAPTER 601 DEFINITIONS.—In this Act [see Short Title of 2012 Amendment note above], any term defined in chapter 601 of title 49, United States Code, has the meaning given that term in that chapter.

''(2) HIGH-CONSEQUENCE AREA.—In this Act, the term 'high-consequence area' means an area described in section 60109(a) of title 49, United States Code.''

§ 60102. Purpose and general authority

(a) PURPOSE AND MINIMUM SAFETY STANDARDS.—

(1) PURPOSE.—The purpose of this chapter is to provide adequate protection against risks to life and property posed by pipeline transportation and pipeline facilities by improving the regulatory and enforcement authority of the Secretary of Transportation.

(2) MINIMUM SAFETY STANDARDS.—The Secretary shall prescribe minimum safety standards for pipeline transportation and for pipeline facilities. The standards—

(A) apply to any or all of the owners or operators of pipeline facilities;

(B) may apply to the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities; and

(C) shall include a requirement that all individuals who operate and maintain pipeline facilities shall be qualified to operate and maintain the pipeline facilities.

(3) QUALIFICATIONS OF PIPELINE OPERATORS.—The qualifications applicable to an individual who operates and maintains a pipeline facility shall address the ability to recognize and react appropriately to abnormal operating conditions that may indicate a dangerous situation or a condition exceeding design limits. The operator of a pipeline facility shall ensure that employees who operate and maintain the facility are qualified to operate and maintain the pipeline facilities.

(b) PRACTICABILITY AND SAFETY NEEDS STANDARDS.—

(1) IN GENERAL.—A standard prescribed under subsection (a) shall be—

(A) practicable; and
(B) designed to meet the need for—
(i) gas pipeline safety, or safely transporting hazardous liquids, as appropriate; and
(ii) protecting the environment.

(2) FACTORS FOR CONSIDERATION.—When prescribing any standard under this section or section 60101(b), 60103, 60108, 60109, 60110, or 60113, the Secretary shall consider—
(A) relevant available—
(i) gas pipeline safety information;
(ii) hazardous liquid pipeline safety information; and
(iii) environmental information;

(B) the appropriateness of the standard for the particular type of pipeline transportation or facility;
(C) the reasonableness of the standard;
(D) based on a risk assessment, the reasonably identifiable or estimated benefits expected to result from implementation or compliance with the standard;
(E) based on a risk assessment, the reasonably identifiable or estimated costs expected to result from implementation or compliance with the standard;
(F) comments and information received from the public; and
(G) the comments and recommendations of the Technical Pipeline Safety Standards Committee, the Technical Hazardous Liquid Pipeline Safety Standards Committee, or both, as appropriate.

(3) RISK ASSESSMENT.—In conducting a risk assessment referred to in subparagraphs (D) and (E) of paragraph (2), the Secretary shall—
(A) identify the regulatory and nonregulatory options that the Secretary considered in prescribing a proposed standard;
(B) identify the costs and benefits associated with the proposed standard;
(C) include—
(i) an explanation of the reasons for the selection of the proposed standard in lieu of the other options identified; and
(ii) with respect to each of those other options, a brief explanation of the reasons that the Secretary did not select the option; and

(D) identify technical data or other information upon which the risk assessment information and proposed standard is based.

(4) REVIEW.—
(A) IN GENERAL.—The Secretary shall—
(i) submit any risk assessment information prepared under paragraph (3) of this subsection to the Technical Pipeline Safety Standards Committee, the Technical Hazardous Liquid Pipeline Safety Standards Committee, or both, as appropriate; and
(ii) make that risk assessment information available to the general public.

(B) PEER REVIEW PANELS.—The committees referred to in subparagraph (A) shall serve as peer review panels to review risk assessment information prepared under this section. Not later than 90 days after receiving risk assessment information for review pursuant to subparagraph (A), each committee that receives that risk assessment information shall prepare and submit to the Secretary a report that includes—
(i) an evaluation of the merit of the data and methods used; and
(ii) any recommended options relating to that risk assessment information and the associated standard that the committee determines to be appropriate.

(C) REVIEW BY SECRETARY.—Not later than 90 days after receiving a report submitted by a committee under subparagraph (B), the Secretary—
(i) shall review the report;
(ii) shall provide a written response to the committee that is the author of the report concerning all significant peer review comments and recommended alternatives contained in the report; and
(iii) may revise the risk assessment and the proposed standard before promulgating the final standard.

(5) SECRETARIAL DECISIONMAKING.—Except where otherwise required by statute, the Secretary shall propose or issue a standard under this Chapter[1] only upon a reasoned determination that the benefits of the intended standard justify its costs.
(6) EXCEPTIONS FROM APPLICATION.—The requirements of subparagraphs (D) and (E) of paragraph (2) do not apply when—
(A) the standard is the product of a negotiated rulemaking, or other rulemaking including the adoption of industry standards that receives no significant adverse comment within 60 days of notice in the Federal Register;
(B) based on a recommendation (in which three-fourths of the members voting concur) by the Technical Pipeline Safety Standards Committee, the Technical Hazardous Liquid Pipeline Safety Standards Committee, or both, as applicable, the Secretary waives the requirements; or
(C) the Secretary finds, pursuant to section 553(b)(3)(B) of title 5, United States Code, that notice and public procedure are not required.

(7) REPORT.—Not later than March 31, 2000, the Secretary shall transmit to the Congress a report that—
(A) describes the implementation of the risk assessment requirements of this section, including the extent to which those requirements have affected regulatory decisionmaking and pipeline safety; and
(B) includes any recommendations that the Secretary determines would make the risk assessment process conducted pursuant to the requirements under this chapter a more effective means of assessing the benefits and costs associated with alternative regulatory and nonregulatory options in prescribing standards under the Federal pipeline safety regulatory program under this chapter.

[1] So in original. Probably should not be capitalized.

(c) PUBLIC SAFETY PROGRAM REQUIREMENTS.—(1) The Secretary shall include in the standards prescribed under subsection (a) of this section a requirement that an operator of a gas pipeline facility participate in a public safety program that—

(A) notifies an operator of proposed demolition, excavation, tunneling, or construction near or affecting the facility;

(B) requires an operator to identify a pipeline facility that may be affected by the proposed demolition, excavation, tunneling, or construction, to prevent damaging the facility; and

(C) the Secretary decides will protect a facility adequately against a hazard caused by demolition, excavation, tunneling, or construction.

(2) To the extent a public safety program referred to in paragraph (1) of this subsection is not available, the Secretary shall prescribe standards requiring an operator to take action the Secretary prescribes to provide services comparable to services that would be available under a public safety program.

(3) The Secretary may include in the standards prescribed under subsection (a) of this section a requirement that an operator of a hazardous liquid pipeline facility participate in a public safety program meeting the requirements of paragraph (1) of this subsection or maintain and carry out a damage prevention program that provides services comparable to services that would be available under a public safety program.

(4) PROMOTING PUBLIC AWARENESS.—

(A) Not later than one year after the date of enactment of the Accountable Pipeline Safety and Accountability Act of 1996,[2] and annually thereafter, the owner or operator of each interstate gas pipeline facility shall provide to the governing body of each municipality in which the interstate gas pipeline facility is located, a map identifying the location of such facility.

(B)(i) Not later than June 1, 1998, the Secretary shall survey and assess the public education programs under section 60116 and the public safety programs under section 60102(c) and determine their effectiveness and applicability as components of a model program. In particular, the survey shall include the methods by which operators notify residents of the location of the facility and its right of way, public information regarding existing One-Call programs, and appropriate procedures to be followed by residents of affected municipalities in the event of accidents involving interstate gas pipeline facilities.

(ii) Not later than one year after the survey and assessment are completed, the Secretary shall institute a rulemaking to determine the most effective public safety and education program components and promulgate if appropriate, standards implementing those components on a nationwide basis. In the event that the Secretary finds that promulgation of such standards are not appropriate, the Secretary shall report to Congress the reasons for that finding.

(d) FACILITY OPERATION INFORMATION STANDARDS.—The Secretary shall prescribe minimum standards requiring an operator of a pipeline facility subject to this chapter to maintain, to the extent practicable, information related to operating the facility as required by the standards prescribed under this chapter and, when requested, to make the information available to the Secretary and an appropriate State official as determined by the Secretary. The information shall include—

(1) the business name, address, and telephone number, including an operations emergency telephone number, of the operator;

(2) accurate maps and a supplementary geographic description, including an identification of areas described in regulations prescribed under section 60109 of this title, that show the location in the State of—

(A) major gas pipeline facilities of the operator, including transmission lines and significant distribution lines; and

(B) major hazardous liquid pipeline facilities of the operator;

(3) a description of—

(A) the characteristics of the operator's pipelines in the State; and

(B) products transported through the operator's pipelines in the State;

(4) the manual that governs operating and maintaining pipeline facilities in the State;

(5) an emergency response plan describing the operator's procedures for responding to and containing releases, including—

(A) identifying specific action the operator will take on discovering a release;

(B) liaison procedures with State and local authorities for emergency response; and

(C) communication and alert procedures for immediately notifying State and local officials at the time of a release; and

(6) other information the Secretary considers useful to inform a State of the presence of pipeline facilities and operations in the State.

(e) PIPE INVENTORY STANDARDS.—The Secretary shall prescribe minimum standards requiring an operator of a pipeline facility subject to this chapter to maintain for the Secretary, to the extent practicable, an inventory with appropriate information about the types of pipe used for the transportation of gas or hazardous liquid, as appropriate, in the operator's system and additional information, including the material's history and the leak history of the pipe. The inventory—

(1) for a gas pipeline facility, shall include an identification of each facility passing through an area described in regulations prescribed under section 60109 of this title but shall exclude equipment used with the compression of gas; and

(2) for a hazardous liquid pipeline facility, shall include an identification of each facility and gathering line passing through an area described in regulations prescribed under section 60109 of this title, whether the facility or gathering line otherwise is subject to this chapter,

[2] See References in Text note below.

but shall exclude equipment associated only with the pipeline pumps or storage facilities.

(f) STANDARDS AS ACCOMMODATING "SMART PIGS".—

(1) MINIMUM SAFETY STANDARDS.—The Secretary shall prescribe minimum safety standards requiring that—

(A) the design and construction of new natural gas transmission pipeline or hazardous liquid pipeline facilities, and

(B) when the replacement of existing natural gas transmission pipeline or hazardous liquid pipeline facilities or equipment is required, the replacement of such existing facilities be carried out, to the extent practicable, in a manner so as to accommodate the passage through such natural gas transmission pipeline or hazardous liquid pipeline facilities of instrumented internal inspection devices (commonly referred to as "smart pigs"). The Secretary may extend such standards to require existing natural gas transmission pipeline or hazardous liquid pipeline facilities, whose basic construction would accommodate an instrumented internal inspection device to be modified to permit the inspection of such facilities with instrumented internal inspection devices.

(2) PERIODIC INSPECTIONS.—Not later than October 24, 1995, the Secretary shall prescribe, if necessary, additional standards requiring the periodic inspection of each pipeline the operator of the pipeline identifies under section 60109 of this title. The standards shall include any circumstances under which an inspection shall be conducted with an instrumented internal inspection device and, if the device is not required, use of an inspection method that is at least as effective as using the device in providing for the safety of the pipeline.

(g) EFFECTIVE DATES.—A standard prescribed under this section and section 60110 of this title is effective on the 30th day after the Secretary prescribes the standard. However, the Secretary for good cause may prescribe a different effective date when required because of the time reasonably necessary to comply with the standard. The different date must be specified in the regulation prescribing the standard.

(h) SAFETY CONDITION REPORTS.—(1) The Secretary shall prescribe regulations requiring each operator of a pipeline facility (except a master meter) to submit to the Secretary a written report on any—

(A) condition that is a hazard to life, property, or the environment; and

(B) safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility.

(2) The Secretary must receive the report not later than 5 working days after a representative of a person to which this section applies first establishes that the condition exists. Notice of the condition shall be given concurrently to appropriate State authorities.

(i) CARBON DIOXIDE REGULATION.—

(1) TRANSPORTATION IN LIQUID STATE.—The Secretary shall regulate carbon dioxide transported by a hazardous liquid pipeline facility. The Secretary shall prescribe standards related to hazardous liquid to ensure the safe transportation of carbon dioxide by such a facility.

(2) TRANSPORTATION IN GASEOUS STATE.—

(A) MINIMUM SAFETY STANDARDS.—The Secretary shall prescribe minimum safety standards for the transportation of carbon dioxide by pipeline in a gaseous state.

(B) CONSIDERATIONS.—In establishing the standards, the Secretary shall consider whether applying the minimum safety standards in part 195 of title 49, Code of Federal Regulations, as in effect on the date of enactment of this paragraph, for the transportation of carbon dioxide in a liquid state to the transportation of carbon dioxide in a gaseous state would ensure safety.

(3) LIMITATION ON STATUTORY CONSTRUCTION.—Nothing in this subsection authorizes the Secretary to regulate piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation, or treatment of carbon dioxide or the preparation of carbon dioxide for transportation by pipeline at production, refining, or manufacturing facilities.

(j) EMERGENCY FLOW RESTRICTING DEVICES.—(1) Not later than October 24, 1994, the Secretary shall survey and assess the effectiveness of emergency flow restricting devices (including remotely controlled valves and check valves) and other procedures, systems, and equipment used to detect and locate hazardous liquid pipeline ruptures and minimize product releases from hazardous liquid pipeline facilities.

(2) Not later than 2 years after the survey and assessment are completed, the Secretary shall prescribe standards on the circumstances under which an operator of a hazardous liquid pipeline facility must use an emergency flow restricting device or other procedure, system, or equipment described in paragraph (1) of this subsection on the facility.

(k) LOW-STRESS HAZARDOUS LIQUID PIPELINES.—

(1) MINIMUM STANDARDS.—Not later than December 31, 2007, the Secretary shall issue regulations subjecting low-stress hazardous liquid pipelines to the same standards and regulations as other hazardous liquid pipelines, except as provided in paragraph (3). The implementation of the applicable standards and regulatory requirements may be phased in. The regulations issued under this paragraph shall not apply to gathering lines.

(2) GENERAL PROHIBITION AGAINST LOW INTERNAL STRESS EXCEPTION.—Except as provided in paragraph (3), the Secretary may not provide an exception to the requirements of this chapter for a hazardous liquid pipeline because the pipeline operates at low internal stress.

(3) LIMITED EXCEPTIONS.—The Secretary shall provide or continue in force exceptions to this subsection for low-stress hazardous liquid pipelines that—

(A) are subject to safety regulations of the United States Coast Guard; or

(B) serve refining, manufacturing, or truck, rail, or vessel terminal facilities if the pipeline is less than 1 mile long (measured outside the facility grounds) and does

not cross an offshore area or a waterway currently used for commercial navigation,

until regulations issued under paragraph (1) become effective. After such regulations become effective, the Secretary may retain or remove those exceptions as appropriate.

(4) RELATIONSHIP TO OTHER LAWS.—Nothing in this subsection shall be construed to prohibit or otherwise affect the applicability of any other statutory or regulatory exemption to any hazardous liquid pipeline.

(5) DEFINITION.—For purposes of this subsection, the term ''low-stress hazardous liquid pipeline'' means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

(6) EFFECTIVE DATE.—The requirements of this subsection shall not take effect as to low-stress hazardous liquid pipeline operators before the effective date of the rules promulgated by the Secretary under this subsection.

(*l*) UPDATING STANDARDS.—The Secretary shall, to the extent appropriate and practicable, update incorporated industry standards that have been adopted as part of the Federal pipeline safety regulatory program under this chapter.

(m) INSPECTIONS BY DIRECT ASSESSMENT.—Not later than 1 year after the date of the enactment of this subsection, the Secretary shall issue regulations prescribing standards for inspection of a pipeline facility by direct assessment.

(n) AUTOMATIC AND REMOTE-CONTROLLED SHUT-OFF VALVES FOR NEW TRANSMISSION PIPELINES.—

(1) IN GENERAL.—Not later than 2 years after the date of enactment of this subsection, and after considering the factors specified in subsection (b)(2), the Secretary, if appropriate, shall require by regulation the use of automatic or remote-controlled shut-off valves, or equivalent technology, where economically, technically, and operationally feasible on transmission pipeline facilities constructed or entirely replaced after the date on which the Secretary issues the final rule containing such requirement.

(2) HIGH-CONSEQUENCE AREA STUDY.—

(A) STUDY.—The Comptroller General of the United States shall conduct a study on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in a high-consequence area.

(B) CONSIDERATIONS.—In conducting the study, the Comptroller General shall consider the swiftness of leak detection and pipeline shutdown capabilities, the location of the nearest response personnel, and the costs, risks, and benefits of installing automatic and remote-controlled shut-off valves.

(C) REPORT.—Not later than 1 year after the date of enactment of this subsection, the Comptroller General shall submit to the Committee on Transportation and Infrastructure and the Committee on Energy and Commerce of the House of Representatives and the Committee on Commerce, Science, and Transportation of the Senate a report on the results of the study.

(*o*) TRANSPORTATION-RELATED OIL FLOW LINES.—

(1) DATA COLLECTION.—The Secretary may collect geospatial or technical data on transportation-related oil flow lines, including unregulated transportation-related oil flow lines.

(2) TRANSPORTATION-RELATED OIL FLOW LINE DEFINED.—In this subsection, the term ''transportation-related oil flow line'' means a pipeline transporting oil off of the grounds of the well where it originated and across areas not owned by the producer, regardless of the extent to which the oil has been processed, if at all.

(3) LIMITATION.—Nothing in this subsection authorizes the Secretary to prescribe standards for the movement of oil through production, refining, or manufacturing facilities or through oil production flow lines located on the grounds of wells.

(p) LIMITATION ON INCORPORATION OF DOCUMENTS BY REFERENCE.—Beginning 1 year after the date of enactment of this subsection, the Secretary may not issue guidance or a regulation pursuant to this chapter that incorporates by reference any documents or portions thereof unless the documents or portions thereof are made available to the public, free of charge, on an Internet Web site.

(Pub. L. 103–272, § 1(e), July 5, 1994, 108 Stat. 1304; Pub. L. 104–304, §§ 4, 20(g), Oct. 12, 1996, 110 Stat. 3794, 3805; Pub. L. 107–355, §§ 20(a)(1), (2)(A), 23, Dec. 17, 2002, 116 Stat. 3009, 3011; Pub. L. 109–468, § 4, Dec. 29, 2006, 120 Stat. 3490; Pub. L. 112–90, §§ 4, 12, 15, 18(b), 24, Jan. 3, 2012, 125 Stat. 1906, 1913, 1915, 1916, 1919.)

HISTORICAL AND REVISION NOTES

Revised Section	Source (U.S. Code)	Source (Statutes at Large)
60102(a)(1) ..	49 App.:1672(a)(1) (1st, 2d sentences).	Aug. 12, 1968, Pub. L. 90–481, § 3(a)(1) (1st, 2d, 7th, 8th sentences), 82 Stat. 721; Oct. 11, 1976, Pub. L. 94–477, § 4(1), 90 Stat. 2073; Nov. 30, 1979, Pub. L. 96–129, §§ 101(a), 109(c)–(e), 93 Stat. 990, 996; Oct. 24, 1992, Pub. L. 102–508, § 101(a)(1), (2), 106 Stat. 3290.
	49 App.:1672(a)(1) (3d sentence).	Aug. 12, 1968, Pub. L. 90–481, 82 Stat. 720, § 3(a)(1) (3d sentence); added Oct. 31, 1988, Pub. L. 100–561, § 101, 102 Stat. 2806; Oct. 24, 1992, Pub. L. 102–508, § 106(1), 102 Stat. 3293.
	49 App.:2002(a)(1) (1st, 2d sentences).	Nov. 30, 1979, Pub. L. 96–129, 203(a)(1), 93 Stat. 1004; Oct. 22, 1986, Pub. L. 99–516, § 3(b)(1)(A), 100 Stat. 2966; Oct. 24, 1992, Pub. L. 102–508, § 201(a)(1), 106 Stat. 3299.
	49 App.:2002(c) (1st sentence).	Nov. 30, 1979, Pub. L. 96–129, § 203(c) (1st sentence), (e), (f), 93 Stat. 1004.
	49 App.:2002(c) (2d sentence).	Nov. 30, 1979, Pub. L. 96–129, 93 Stat. 989, § 203(c) (2d sentence); added Oct. 31, 1988, Pub. L. 100–561, § 201, 102 Stat. 2809; Oct. 24, 1992, Pub. L. 102–508, § 205(1), 106 Stat. 3302.
60102(a)(2) ..	49 App.:1672(a)(1) (4th, 5th sentences).	Aug. 12, 1968, Pub. L. 90–481, 82 Stat. 720, § 3(a)(1) (4th, 5th sentences); added Oct. 24, 1992, Pub. L. 102–508, § 106(2), 102 Stat. 3293.
	49 App.:2002(c) (3d, 4th sentences).	Nov. 30, 1979, Pub. L. 96–129, 93 Stat. 989, § 203(c) (3d, 4th sentences); added Oct. 24, 1992, Pub. L. 102–508, § 205(2), 106 Stat. 3302.

EFFECTIVE DATE NOTE: Amendments to §192.473 were published at 87 FR 52269, Aug. 24, 2022, effective May 24, 2023.

§ 192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m^3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192–4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192–33, 43 FR 39390, Sept. 5, 1978; Amdt. 192–78, 61 FR 28785, June 6, 1996; Amdt. 192–85, 63 FR 37504, July 13, 1998]

§ 192.476 Internal corrosion control: Design and construction of transmission line.

(a) *Design and construction.* Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) *Exceptions to applicability.* The design and construction requirements of paragraph (a) of this section do not apply to the following:

(1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) *Change to existing transmission line.* When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) *Records.* An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

[72 FR 20059, Apr. 23, 2007]

§ 192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Amdt. 192–33, 43 FR 39390, Sept. 5, 1978]

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation. (eff. 5-24-2023)

(a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either

by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary.

(b) The monitoring and mitigation program described in paragraph (a) of this section must include:

(1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

(2) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects.

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

[87 FR 52270, Aug. 24, 2022]

EFFECTIVE DATE NOTE: At 87 FR 52270, Aug. 24, 2022, § 192.478 was added, effective May 24, 2023.

§ 192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Amdt. 192–93, 68 FR 53901, Sept. 15, 2003]

§ 192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	Then the frequency of inspection is:
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
(3) Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by § 192.479.

(d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

[Amdt. 192–93, 68 FR 53901, Sept. 15, 2003, as amended at 86 FR 2240, Jan. 11, 2021]

Title 49 —Transportation
Subtitle B —Other Regulations Relating to Transportation
Chapter I —Pipeline and Hazardous Materials Safety Administration, Department of Transportation
Subchapter D —Pipeline Safety
Part 192 —Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards
Subpart M —Maintenance

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq.*, and 49 CFR 1.97.
Source: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.

Editorial Note: Nomenclature changes to part 192 appear at 71 FR 33406, June 9, 2006.

§ 192.712 Analysis of predicted failure pressure and critical strain level.

(a) *Applicability.* Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) *Corrosion metal loss.* When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, *see* § 192.7); R–STRENG (incorporated by reference, *see* § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph (b) introductory text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

(2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R–STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR–MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

(5) Identify and quantify all previous and present significant loads acting on the dent.

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

(7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

(8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with § 192.713, § 192.714, or § 192.933, as applicable.

(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

(10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

(d) ***Cracks and crack-like defects —***

(1) ***Crack analysis models.*** When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

(2) ***Analysis for crack growth and remaining life.*** If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(3) ***Cracks that survive pressure testing.*** For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;

(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.

(e) ***Data.*** In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows.

(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using *in situ* direct measurements.

(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:

(i) ***Material toughness.*** An operator must use one of the following for material toughness:

(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;

(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

(ii) ***Material strength.*** An operator must assume one of the following for material strength:

(A) Grade A pipe (30,000 psi), or

(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(iii) ***Pipe dimensions and other data.*** Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.

(f) ***Review.*** Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

(g) ***Records.*** An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

(8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

(9) Pressure test data and results;

(10) In-the-ditch assessments;

(11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(12) All finite element analysis results;

(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

(h) ***Reassessments.*** If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

(1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

(2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

[Amdt. 192–125, 84 FR 52251, Oct. 1, 2019, as amended by Amdt. 192–132, 87 FR 52270, Aug. 24, 2022]

must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

(8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

(9) Pressure test data and results;

(10) In-the-ditch assessments;

(11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(12) All finite element analysis results;

(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

[Amdt. No. 192–125, 84 FR 52251, Oct. 1, 2019]

EFFECTIVE DATE NOTE: Amendments to §192.712 were published at 87 FR 52270, Aug. 24, 2022, effective May 24, 2023.

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe; or

(2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Operating pressure must be at a safe level during repair operations.

[Amdt. 192–88, 64 FR 69665, Dec. 14, 1999]

§ 192.714 Transmission lines: Repair criteria for onshore transmission pipelines. (eff. 5-24-2023)

(a) *Applicability*. This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in §192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§192.112, 192.328, and 192.620 must comply with §192.620(d)(11).

(b) *General*. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with §192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through §192.607.

(c) *Schedule for evaluation and remediation*. An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that

meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or

(2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.

(d) *Remediation of certain conditions.* For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) *Two-year conditions.* An operator must repair the following conditions within 2 years of discovery:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower ⅓ of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with §192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with §192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with §192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

(i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom ⅓ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with §192.712(c) determines that critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with §192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

(iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with §192.712(c) demonstrates critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with §192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with §192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with §192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *Temporary pressure reduction.* (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected

pipeline to any one of the following based on safety considerations for the public and operating personnel:

(i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(iii) A level not exceeding the predicted failure pressure divided by 1.1.

(2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.

(3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds 365 days, an operator must notify PHMSA in accordance with § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

(f) *Other conditions.* Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

(g) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

(h) *Determining predicted failure pressures and critical strain levels.* An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

[87 FR 52270, Aug. 24, 2022]

EFFECTIVE DATE NOTE: § 192.714 was published at 87 FR 52270, Aug. 24, 2022, effective May 24, 2023.

§ 192.715 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.

(b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking;

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch (3.2 millimeters) thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement

Title 49 —Transportation
Subtitle B —Other Regulations Relating to Transportation
Chapter I —Pipeline and Hazardous Materials Safety Administration, Department of Transportation
Subchapter D —Pipeline Safety
Part 192 —Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards
Subpart O —Gas Transmission Pipeline Integrity Management

Source: 68 FR 69817, Dec. 15, 2003, unless otherwise noted.
Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et. seq.*, and 49 CFR 1.97.
Source: 35 FR 13257, Aug. 19, 1970, unless otherwise noted.

Editorial Note: Nomenclature changes to part 192 appear at 71 FR 33406, June 9, 2006.

§ 192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking?

(a) *Definition.* A Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipeline segment for the presence of stress corrosion cracking (SCC) by systematically gathering and analyzing excavation data from pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements.* An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, *see* § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

(1) *Data gathering and integration.* An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, *see* § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, *see* § 192.7) indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, *see* § 192.7), and must include, at a minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, *see* § 192.7). Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

(iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;

(iv) The effects of coatings that shield CP when disbonded from the pipe; and

(v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) ***Indirect inspection.*** In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

(3) ***Direct examination.*** In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.

(4) ***Remediation and mitigation.*** If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.

(ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in § 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.

(5) ***Post assessment.*** An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, "periodic reassessment," and 6.4, "effectiveness of SCCDA," must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:

(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, *see* § 192.7);

(ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

[Amdt. 192–132, 87 FR 52276, Aug. 24, 2022]

Title 49 —Transportation
Subtitle B —Other Regulations Relating to Transportation
Chapter I —Pipeline and Hazardous Materials Safety Administration, Department of Transportation
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Part 192 —Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards
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Editorial Note: Nomenclature changes to part 192 appear at 71 FR 33406, June 9, 2006.

§ 192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator must use the conservative assumptions in either § 192.712(e)(2) or, if appropriate following a pressure test, in § 192.712(d)(3).

(1) *Temporary pressure reduction.*

(i) If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must reduce the operating pressure to one of the following:

(A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered;

(B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(C) A level not exceeding the predicted failure pressure divided by 1.1.

(ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The

operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. For the purposes of this section, a condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable. In cases where a determination is not made within the 180-day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation —*

(1) *Immediate repair conditions.* An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 (incorporated by reference, *see* § 192.7) in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper $^2/_3$ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

(vi) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

(2) ***One-year conditions.*** Except for conditions listed in paragraphs (d)(1) and (3) of this section, an operator must remediate any of the following within 1 year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper $^2/_3$ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower $^1/_3$ of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions.* An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), located between the 4 o'clock position and the 8 o'clock position (bottom $^{1}/_{3}$ of the pipe), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper $^{2}/_{3}$ of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *In situ direct examination of crack defects.* Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ"

examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192–95, 69 FR 18233, Apr. 6, 2004; Amdt. 192–104, 72 FR 39016, July 17, 2007; Amdt. 192–119, 80 FR 182, Jan. 5, 2015; 80 FR 46847, Aug. 6, 2015; Amdt. No. 192–125, 84 FR 52254, Oct. 1, 2019; Amdt. 192–132, 87 FR 52277, Aug. 24, 2022; Amdt. 192–133, 88 FR 24712, Apr. 24, 2023]

CERTIFICATE OF SERVICE

I certify that on December 5, 2023, the foregoing brief was electronically filed through this Court's CM/ECF system, which will send a notice of filing to all registered users.

/s/ Catherine E. Stetson
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